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Federal Register

Vol. 56, No. 232

Tuesday, December 3, 1991

DEPARTMENT OF AGRICULTURE

Agricultural Marketing Service

7 CFR Part 905

[Docket No. FV-91-432FR]

Increase in 1991–92 Budgeted Expenditures Under the Marketing Order Covering Oranges, Grapefruit, Tangerines, and Tangelos Grown in Florida

AGENCY: Agricultural Marketing Service, USDA.

ACTION: Final rule.

SUMMARY: This rule increases authorized expenditures by $6,000 for the 1991–92 fiscal year (August 1–July 31) under Marketing Order No. 905. This action increases authorized expenditures to $216,000, up from $210,000. The $6,000 will be added to the "Appropriated Reserve" which was created to be utilized this season for a "Mexico-Texas Citrus Tour," scheduled to take place in March 1992. This season, the tour will encompass the Texas Valley and the citrus producing regions of Mexico.

This action is needed for the Citrus Administrative Committee (committee) to pay additional anticipated expenses associated with the tour. The committee's initial cost estimate of $20,000 for this purpose was not adequate to cover the cost. The action will enable the committee to continue to perform its duties and the marketing order to operate.

EFFECTIVE DATE: August 1, 1991 through July 31, 1992.

FOR FURTHER INFORMATION CONTACT: Gary D. Rasmussen, Marketing Specialist, Marketing Order Administration Branch, Fruit and Vegetable Division, AMS, USDA, P.O. Box 96456, room 2525-S, Washington, DC 20090–6456; telephone: (202) 475–3918.

SUPPLEMENTARY INFORMATION: This final rule is issued under Marketing Agreement and Marketing Order No. 905, both as amended (7 CFR part 905), regulating the handling of oranges, grapefruit, tangerines, and tangelos grown in Florida, hereinafter referred to as the order. The agreement and order is effective under the Agricultural Marketing Agreement Act of 1937, as amended (7 U.S.C. 601–674), hereinafter referred to as the Act.

This final rule has been reviewed by the Department of Agriculture (Department) in accordance with Departmental Regulation 1512–1 and the criteria contained in Executive Order 12291 and has been determined to be a "non-major" rule.

Pursuant to requirements set forth in the Regulatory Flexibility Act (RFA), the Administrator of the Agricultural Marketing Service (AMS) has considered the economic impact of this final rule on small entities.

The purpose of the RFA is to fit regulatory actions to the scale of business subject to such actions in order that small businesses will not be unduly or disproportionately burdened. Marketing orders issued pursuant to the Act, and rules issued thereunder, are unique in that they are brought about through group action of essentially small entities acting on their own behalf. Thus, both statutes have small entity orientation and compatibility.

There are about 100 citrus handlers subject to regulation under the marketing order covering fresh oranges, grapefruit, tangerines, and tangelos grown in Florida, and about 10,200 producers of these fruits in Florida. Small agricultural producers have been defined by the Small Business Administration (13 CFR 121.601) as those having annual receipts of less than $500,000, and small agricultural service firms are defined as those whose annual receipts are less than $3,500,000. A minority of these handlers and a majority of these producers may be classified as small entities.

A final rule was published in the **Federal Register** (56 FR 32061, July 15, 1991), authorizing expenditures of $210,000 and an assessment rate of $0.0025 per ⅘ bushel carton of fresh fruit shipped under M.O. 905 for the fiscal year ending July 31, 1992.

The proposed rule concerning this increase was published in the **Federal Register** (56 FR 50677, October 8, 1991). That rule requested that interested persons file comments by November 7, 1991. No comments were received.

The Citrus Administrative Committee (committee) met on September 10, 1991, and unanimously recommended a $6,000 increase in 1991–92 budgeted expenditures to $216,000, up from the $210,000 currently authorized. The $6,000 will be added to the "Appropriated Reserve" which was created to be utilized this season for the "Mexico-Texas Citrus Tour," scheduled for March 1992. This season, the tour will encompass the Texas Valley and the citrus producing regions of Mexico. This action is needed by the committee to pay additional anticipated expenses associated with the tour. The committee's earlier cost estimate of $20,000 for the tour was not adequate to cover the cost.

The committee plans to finance this additional $6,000 of expenses by drawing funds from its reserve fund, which is adequate to cover the contemplated additional expenditures. Thus, no increase in the current assessment rate is necessary. This action will enable the committee to continue to perform its duties and the marketing order to operate.

While this action will impose some additional costs on handlers, the costs are in the form of uniform assessments on all handlers. Some of the additional costs may be passed on to producers. However, these costs will be significantly offset by the benefits derived from the operation of the marketing order. Based on the above, the Administrator of the AMS has determined that this action will not have a significant economic impact on a substantial number of small entities.

After consideration of the information and recommendations submitted by the committee and other available information, it is found that this final rule will tend to effectuate the declared policy of the Act.

Pursuant to 5 U.S.C. 553, it is also found and determined that good cause exists for not postponing the effective date of this action until 30 days after publication in the **Federal Register** because approval of the increased expenditures must be expedited. The fiscal year for this marketing order

began on August 1, 1991, and the committee needs sufficient funds to pay its expenses, which are incurred on a continuous basis.

List of Subjects in 7 CFR Part 905

Grapefruit, Marketing agreements, Oranges, Reporting and recordkeeping requirements, Tangelos, Tangerines.

For the reasons set forth in the preamble, 7 CFR part 905 is amended as follows:

PART 905—ORANGES, GRAPEFRUIT, TANGERINES, AND TANGELOS GROWN IN FLORIDA

1. The authority citation for 7 CFR part 905 continues to read as follows:

Authority: Secs. 1–19, 48 Stat. 31, as amended; 7 U.S.C. 601–674.

2. Section 905.230 is revised to read as follows:

Note: This section will not appear in the annual Code of Federal Regulations.

§ 905.230 Expenses and assessment rate.

Expenses of $216,000 by the Citrus Administrative Committee are authorized, and an assessment rate of $0.0025 per ⅘ bushel carton of assessable fruit is established for the fiscal year ending July 31, 1992. Any unexpended funds from the 1990–91 fiscal year may be carried over as a reserve.

Dated: November 25, 1991.

Robert C. Keeney,

Deputy Director, Fruit and Vegetable Division.

[FR Doc. 91–28810 Filed 12–2–91; 8:45 am]

BILLING CODE 3410–02–M

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7 CFR Part 1004

[Docket No. AO–160–A65–RO–2; DA–90–003]

Milk in the Middle Atlantic Marketing Area; Order Amending Order

AGENCY: Agricultural Marketing Service, USDA.

ACTION: Final rule.

SUMMARY: This action adopts for the Middle Atlantic Federal milk order a plan for pricing milk on the basis of its nonfat solids content, as well as its volume and butterfat content. The differential value of milk used in Class I and Class II will be pooled to determine producers' shares of the higher-valued uses, and the value of nonfat solids used in Classes II and III will be pooled with the value of skim milk used in Class I to determine the value of nonfat solids in producer milk. The changes will incorporate recognition of the value of nonfat milk solids contained in milk pooled under the order.

The amendments to the order have been approved by cooperative associations representing more than two-thirds of the producers on the Middle Atlantic market.

EFFECTIVE DATE: January 1, 1992.

FOR FURTHER INFORMATION CONTACT: Constance M. Brenner, Marketing Specialist, USDA/AMS/Dairy Division, Order Formulation Branch, room 2968, South Building, P.O. Box 96456, Washington, DC 20090–6456, (202) 720–7183.

SUPPLEMENTARY INFORMATION: Prior documents in this proceeding:

Notice of Hearing: Issued June 29, 1990; published July 9, 1990 (55 FR 28052).

Recommended Decision: Issued May 23, 1991; published May 31, 1991 (56 FR 24746).

Final Decision: Issued November 5, 1991; published November 14, 1991 (56 FR 57850).

Findings and Determinations

The findings and determinations hereinafter set forth supplement those that were made when the Middle Atlantic order was first issued and when it was amended. The previous findings and determinations are hereby ratified and confirmed, except where they may conflict with those set forth herein.

(a) Findings upon the basis of the hearing record. Pursuant to the provisions of the Agricultural Marketing Agreement Act of 1937, as amended (7 U.S.C. 601–674), and the applicable rules of practice and procedure governing the formulation of marketing agreements and marketing orders (7 CFR part 900), a public hearing was held upon certain proposed amendments to the tentative marketing agreement and to the order regulating the handling of milk in the Middle Atlantic marketing area.

Upon the basis of the evidence introduced at such hearing and the record thereof, it is found that:

(1) The said order as hereby amended, and all of the terms and conditions thereof, will tend to effectuate the declared policy of the Act;

(2) The parity prices of milk, as determined pursuant to section 2 of the Act, are not reasonable in view of the price of feeds, available supplies of feeds, and other economic conditions which affect market supply and demand for milk in the said marketing area; and the minimum prices specified in the order as hereby amended, are such prices as will reflect the aforesaid factors, insure a sufficient quantity of pure and wholesome milk, and be in the public interest; and

(3) The said order as hereby amended regulates the handling of milk in the same manner as, and is applicable only to persons in the respective classes of industrial or commercial activity specified in, a marketing agreement upon which a hearing has been held.

(b) Determinations. It is hereby determined that:

(1) The refusal or failure of handlers (excluding cooperative associations specified in section 8c(9) of the Act) of more than 50 percent of the milk, which is marketed within the marketing area, to sign a proposed marketing agreement, tends to prevent the effectuation of the declared policy of the Act;

(2) The issuance of this order amending the order is the only practical means pursuant to the declared policy of the Act of advancing the interests of producers as defined in the order; and

(3) The issuance of the order amending the order is approved or favored by at least two-thirds of the producers who during the determined representative period were engaged in the production of milk for sale in the marketing area.

List of Subjects in 7 CFR Part 1004

Milk marketing orders.

Order Relative to Handling

It is therefore ordered, That on and after the effective date hereof, the handling of milk in the Middle Atlantic marketing area shall be in conformity to and in compliance with the terms and conditions of the aforesaid order, as amended, and as hereby further amended, as follows:

PART 1004—MILK IN THE MIDDLE ATLANTIC MARKETING AREA

1. The authority citation for 7 CFR part 1004 continues to read as follows:

Authority: Secs. 1–19, 48 Stat. 31, as amended; 7 U.S.C. 601–674.

2. Section 1004.30 is revised to read as follows:

§ 1004.30 Reports of receipts and utilization.

(a) On or before the eighth day after the end of each month each handler with respect to each of the handler's pool plants shall report for the month to the market administrator in the detail and on forms prescribed by the market administrator as follows:

(1) The quantities of skim milk and butterfat contained in:

(i) Receipts of producer milk (including such handler's own production) and milk received from a cooperative association for which it is a handler pursuant to § 1004.9(c), and the pounds of nonfat milk solids contained in such receipts;

(ii) Receipts of fluid milk products and bulk fluid cream products from other pool plants; and

(iii) Receipts of other source milk;

(2) The quantities of skim milk and butterfat in inventories at the beginning and end of the month of fluid milk products and products specified in § 1004.40(b)(1); and

(3) The utilization or disposition of all skim milk and butterfat required to be reported pursuant to this paragraph, showing separately in-area route disposition, except filled milk, and filled milk route disposition in the marketing area;

(b) Each handler who operates a partially regulated distributing plant shall report as required in paragraph (a) of this section, except that receipts of milk from dairy farmers shall be reported in lieu of producer milk and that the market administrator may waive the reporting of nonfat milk solids; such report shall include a separate statement showing the quantity of reconstituted skim milk in fluid milk products disposed of on routes in the marketing area;

(c) Each producer-handler and each handler pursuant to § 1004.9(e) shall make reports to the market administrator at such time and in such manner as the market administrator may prescribe; and

(d) On or before the eighth day after the end of each month, each cooperative association and/or a federation of cooperative associations shall report with respect to milk for which it is a handler pursuant to § 1004.9 (b) or (c) as follows:

(1) Receipts of skim milk, butterfat and nonfat milk solids from producers;

(2) Utilization of skim milk, butterfat and nonfat milk solids diverted to nonpool plants; and

(3) The quantities of skim milk, butterfat and nonfat milk solids delivered to each pool plant of another handler.

3. Section 1004.32 Other reports, is amended by revising paragraphs (a)(1)(iii), (a)(2) and (d)(2) to read as follows:

§ 1004.32 Other reports.

(a) * * *

(1) * * *

(iii) The average butterfat content and average nonfat milk solids content of such milk; and

* * * * *

(2) Such other information with respect to receipts and utilization of butterfat, skim milk and nonfat milk solids as the market administrator shall prescribe.

* * * * *

(d) * * *

(2) The total pounds of milk involved in the transaction, and the average butterfat and nonfat milk solids content of such milk; and

* * * * *

4. Section 1004.50 Class and component prices, is amended by adding new paragraphs (d) through (f), to read as follows:

§ 1004.50 Class and component prices.

* * * * *

(d) *Butterfat price.* The butterfat price per pound shall be a figure computed as follows:

(1) Compute a butterfat differential per 1 percent butterfat by multiplying the simple average for the month of the daily prices per pound of Grade A (92-score) butter by 1.38, and subtract from the result an amount determined by multiplying the average price per hundredweight, at test, for manufacturing grade milk, f.o.b. plants in Minnesota and Wisconsin, as reported by the Department for the month, by 0.028. The butter price means the simple average for the month of the daily prices per pound of Grade A (92-score) butter. The prices used shall be those of the Chicago Mercantile Exchange as reported and published weekly by the Dairy Division, Agricultural Marketing Service. The average shall be computed by the Director of the Dairy Division using the price reported each week as the daily price for that day and for each following day until the next price is reported.

(2) Multiply the butterfat differential obtained in paragraph (d)(1) of this section by 3.5, and subtract the resulting amount from the Class III price;

(3) Divide the value obtained from the calculations of paragraph (d)(2) of this section by 100; and

(4) Add to the resulting amount the butterfat differential computed in paragraph (d)(1) of this section. The sum thereof shall be the price per pound for producer butterfat for the month.

(e) *Nonfat milk solids price.* The price per pound for nonfat milk solids shall be computed by subtracting from the Class III price the butterfat price multiplied by 3.5, and dividing the result by the average percentage of nonfat milk solids in all producer milk for the month.

(f) *Skim milk price.* The skim milk price per hundredweight shall be the Class III price for the month adjusted to remove the value of 3.5 percent butterfat and rounded to the nearest cent. Such adjustment shall be computed by multiplying the butterfat differential pursuant to paragraph (d)(1) of this section by 3.5 and subtracting the result from the Class III price.

5. Section 1004.51 Basic formula prices, is amended by revising the last sentence of paragraph (a) to read as follows: "For such adjustment the butterfat differential pursuant to § 1004.50 (d)(1), rounded to the nearest cent, shall be used."

6. Section 1004.53 is amended by revising the section heading and paragraph (a)(3) to read as follows:

§ 1004.53 Announcement of class prices and component prices.

* * * * *

(a) * * *

(3) The prices for butterfat and skim milk computed pursuant to § 1004.50(d) and (f).

* * * * *

7. Section 1004.54 is revised to read as follows:

§ 1004.54 Equivalent prices or indexes.

If for any reason a price or pricing constituent required by this order for computing class prices or for other purposes is not available as prescribed in this order, the market administrator shall use a price or pricing constituent determined by the Secretary to be equivalent to the price or pricing constituent that is required.

8. The heading "Uniform Prices" before § 1004.60 is changed to read "Differential Pool and Handler Obligations."

9. Section 1004.60 is revised to read as follows:

§ 1004.60 Handler's value of milk for computing uniform prices.

The market administrator shall compute each month for each handler defined in § 1004.9(a) with respect to each of such handler's pool plants, and for each handler defined in § 1004.9 (b) and (c), an obligation to the pool computed by adding the following values:

(a) The pounds of milk received from a cooperative association as a handler pursuant to § 1004.9(c) and allocated to Class I pursuant to § 1004.44(a)(14) and the corresponding step of § 1004.44(b), and the pounds of producer milk in Class I as determined pursuant to

§ 1004.44, both multiplied by the difference between the Class I price (adjusted pursuant to § 1004.52) and the Class III price;

(b) The pounds of milk received from a cooperative association as a handler pursuant to § 1004.9(c) and allocated to Class II pursuant to § 1004.44(a)(14) and the corresponding step of § 1004.44(b), and the pounds of producer milk in Class II as determined pursuant to § 1004.44, both multiplied by the difference between the Class II price and Class III price;

(c) The value of the product pounds, skim milk, and butterfat in overage assigned to each class pursuant to § 1004.44(a)(15) and the value of the corresponding pounds of nonfat milk solids associated with the skim milk subtracted from Class II and Class III pursuant to § 1004.44(a)(15), by multiplying the skim milk pounds so assigned by the percentage of nonfat milk solids in the handler's receipts of producer skim milk during the month, as follows:

(1) The hundredweight of skim milk and butterfat subtracted from Class I pursuant to § 1004.44(a)(15) and the corresponding step of § 1004.44(b), multiplied by the difference between the Class I price adjusted for location and the Class III price, plus the hundredweight of skim milk subtracted from Class I pursuant to § 1004.44(a)(15) multiplied by the skim milk price, plus the butterfat pounds of overage subtracted from Class I pursuant to § 1004.44(b) multiplied by the butterfat price;

(2) The hundredweight of skim milk and butterfat subtracted from Class II pursuant to § 1004.44(a)(15) and the corresponding step of § 1004.44(b) multiplied by the difference between the Class II price and the Class III price, plus the pounds of nonfat milk solids in skim milk subtracted from Class II pursuant to § 1004.44(a)(15) multiplied by the nonfat milk solids price, plus the butterfat pounds of overage subtracted from Class II pursuant to § 1004.44(b) multiplied by the butterfat price;

(3) The pounds of nonfat milk solids in skim milk overage subtracted from Class III pursuant to § 1004.44(a)(15) multiplied by the nonfat milk solids price, plus the butterfat pounds of overage subtracted from Class III pursuant to § 1004.44(b) multiplied by the butterfat price;

(d) For the first month that this paragraph is effective, the value of the hundredweight of skim milk and butterfat subtracted from Class I and Class II pursuant to § 1004.44(a)(10) and the corresponding step of § 1004.44(b), as follows:

(1) The value of the hundredweight of skim milk and butterfat subtracted from Class I pursuant to § 1004.44(a)(10) and the corresponding step of § 1004.44(b) applicable at the location of the pool plant at the difference between the current month's Class I price and the previous month's Class III price;

(2) The value of the hundredweight of skim milk and butterfat subtracted from Class II pursuant to § 1004.44(a)(10) and the corresponding step of § 1004.44(b) at the difference between the current month's Class II price and the Class III price for the previous month;

(e) For the second and subsequent months that this paragraph is effective, the value of the product pounds, skim milk, and butterfat subtracted from Class I or Class II pursuant to § 1004.44(a)(10) and the corresponding step of § 1004.44(b), and the value of the pounds of nonfat milk solids associated with the skim milk subtracted from Class II pursuant to § 1004.44(a)(10), computed by multiplying the skim milk pounds so subtracted by the percentage of nonfat milk solids in the handler's receipts of producer skim milk during the previous month, as follows:

(1) The value of the product pounds, skim milk and butterfat subtracted from Class I pursuant to § 1004.44(a)(10) and the corresponding step of § 1004.44(b) applicable at the location of the pool plant at the current month's Class I-Class III price difference and the current month's skim milk and butterfat prices, less the Class III value of the milk at the previous month's nonfat milk solids and butterfat prices;

(2) The value of the hundredweight of skim milk and butterfat subtracted from Class II pursuant to § 1004.44(a)(10) and the corresponding step of § 1004.44(b) at the current month's Class II-Class III price difference and the current month's nonfat milk solids and butterfat prices, less the Class III value of the milk at the previous month's nonfat milk solids and butterfat prices;

(f) The value of the product pounds, skim milk and butterfat subtracted from Class I pursuant to § 1004.44(a)(8) (i) through (iv), and the corresponding step of § 1004.44(b), excluding receipts of bulk fluid cream products from another order plant, applicable at the location of the pool plant at the current month's Class I-Class III price difference;

(g) The value of the product pounds, skim milk and butterfat subtracted from Class I pursuant to § 1004.44(a)(8) (v) and (vi) and the corresponding step of § 1004.44(b) applicable at the location of the transferor-plant at the current month's Class I-Class III price difference;

(h) The value of the product pounds, skim milk and butterfat subtracted from Class I pursuant to § 1004.44(a)(12) and the corresponding step of § 1004.44(b), excluding such hundredweight in receipts of bulk fluid milk products from an unregulated supply plant to the extent that an equivalent quantity disposed of to such plant by handlers fully regulated by any Federal order is classified and priced as Class I milk and is not used as an offset for any other payment obligation under any order, applicable at the location of the nearest unregulated supply plants from which an equivalent volume was received at the current month's Class I-Class III price difference;

(i) The pounds of skim milk received from a cooperative association as a handler pursuant to § 1004.9(c) and allocated to Class I pursuant to § 1004.44(a)(14), and the pounds of producer milk in Class I as determined pursuant to § 1004.44, both multiplied by the skim milk price for the month computed pursuant to § 1004.50(f);

(j) The pounds of nonfat milk solids in skim milk in receipts allocated to Class II and Class III pursuant to § 1004.44(a)(14) and in producer milk classified as Class II and Class III pursuant to § 1004.44, computed by multiplying the skim milk pounds so assigned by the percentage of nonfat milk solids in the handler's receipts of producer skim milk during the month for each report filed, separately, the result to be multiplied by the nonfat milk solids price for the month computed pursuant to § 1004.50(e).

10. Section 1004.61 is revised to read as follows:

§ 1004.61 Computation of weighted average differential price, weighted average differential price for base milk, and producer nonfat milk solids price.

For each month the market administrator shall compute a "weighted average differential price", a "weighted average differential price for base milk" received from producers, and a "producer nonfat milk solids price", and follows:

(a) The "weighted average differential price" shall be the result of the following computations:

(1) Combine into one total:

(i) The value computed pursuant to § 1004.60 (a) through (h) for all handlers who filed the reports prescribed by § 1004.30 for the month and who made the payments pursuant to § 1004.71 for the preceding month;

(ii) An amount equal to the total value of the location differentials computed pursuant to § 1004.75;

(iii) An amount equal to not less than one-half of the unobligated balance in the producer-settlement fund.

(2) Divide the total value calculated under paragraph (a)(1) of this section by the sum of the following for all handlers:

(i) The total hundredweight of producer milk pursuant to § 1004.13 represented by the value established pursuant to (1)(i) of this paragraph; and

(ii) The total hundredweight for which a value is computed pursuant to § 1004.60(h).

(3) Subtract not less than 4 cents nor more than 5 cents per hundredweight. The result shall be the "Weighted average differential price."

(b) Compute the "Weighted average differential price for base milk" as follows:

(1) Subtract from the total value calculated pursuant to paragraph (a)(1) of this section an amount computed by multiplying the hundredweight of milk for which a value is computed pursuant to § 1004.60(h) by the weighted average differential price computed pursuant to paragraph (a) of this section; and

(2) Divide the result obtained in (b)(1) by the total hundredweight of base milk for handlers included in the computations pursuant to paragraph (a)(1)(i) of this section and subtract not less than 4 cents nor more than 5 cents per hundredweight. The result shall be the "weighted average differential price for base milk."

(c) The "Producer nonfat milk solids price" to be paid to all producers for the pounds of nonfat milk solids contained in their milk shall be computed by the market administrator each month as follows:

(1) Combine into one total the values computed pursuant to § 1004.60 (i) and (j) for all handlers who made reports pursuant to § 1004.30 and who made payments pursuant to § 1004.71 for the preceding month;

(2) Divide the resulting amount by the total pounds of nonfat milk solids in producer milk; and

(3) Round by subtracting a positive amount not to exceed one cent. The result is the "Producer nonfat milk solids price."

11. Section 1004.62 is revised to read as follows:

§ 1004.62 Computation of uniform price.

A uniform price for producer milk containing 3.5 percent butterfat shall be computed by adding the weighted average differential price determined pursuant to § 1004.61(a) to the Class III price.

12. A new § 1004.63 is added under the new heading "Differential Pool and Handler Obligations." to read as follows:

§ 1004.63 Announcement of weighted average differential price, weighted average differential price for base milk, nonfat milk solids price and producer nonfat milk solids price.

On or before the 13th day of each month, the market administrator shall publicly announce for the preceding month by posting in a conspicuous place in his office and by such other means as he deems appropriate, the weighted average differential price, the weighted average differential price for base milk and the producer nonfat milk solids price computed pursuant to § 1004.61, and the price for nonfat milk solids computed pursuant to § 1004.50(e).

13. Section 1004.71 is amended by revising paragraph (b) to read as follows and removing paragraph (c):

§ 1004.71 Payments to the producer-settlement fund.

* * * * *

(b) The sum of:

(1) The value of milk received by such handler from producers and from cooperative association handlers pursuant to § 1004.9(c) at the applicable price(s) pursuant to § 1004.61 adjusted by applicable location differentials, less in the case of a cooperative association on milk for which it is a handler pursuant to § 1004.9(c), the amount due from other handlers pursuant to § 1004.74(d); and

(2) The value at the weighted average differential price, computed pursuant to § 1004.62, adjusted by the applicable location differential on nonpool milk pursuant to § 1004.75(b), with respect to other source milk for which a value was computed pursuant to § 1004.60(h).

§ 1004.74 [Removed]

§ 1004.73 [Redesignated as § 1004.74 and Amended]

14. Section 1004.74 is removed, § 1004.73 is re-designated as § 1004.74 and amended by revising paragraphs (a)(2), (c), (d)(2) and (e)(2), and a new § 1004.73 is added, to read as follows:

§ 1004.73 Value of producer milk.

The total value of milk received from producers during any month shall be the sum of the following calculations:

(a) The value of a producer's base milk shall be the sum of the following:

(1) The weighted average differential price for base milk computed pursuant to § 1004.61(b) subject to the appropriate plant location adjustment times the total hundredweight of base milk received from the producer;

(2) The total nonfat milk solids contained in the producer milk received from the producer multiplied by the producer nonfat milk solids price computed pursuant to § 1004.61; and

(3) The total butterfat contained in the producer milk received from the producer times the butterfat price computed pursuant to § 1004.50(d).

(b) The value of a producer's excess milk shall be the sum of the values computed pursuant to paragraphs (a) (2) and (3) of this section.

§ 1004.74 Payments to producers and to cooperative associations.

(a) * * *

(2) On or before the 20th of the following month at not less than the total amount computed in accordance with the provisions set forth in § 1004.73 with respect to such milk, subject to the following adjustments:

* * * * *

(c) In the case of milk received by a handler from a cooperative association in its capacity as the operator of a pool plant such handler shall on or before the second day prior to the date on which payments are due individual producers, pay to such cooperative association for milk so received during the month, an amount not less than the value of such milk computed at the applicable class and/or component prices for the location of the plant of the buying handler; and

(d) * * *

(2) A final payment equal to the total value of such milk computed pursuant to § 1004.73, adjusted by the applicable differentials pursuant to § 1004.75, less the amount of partial payment on such milk.

(e) * * *

(2) The total pounds, average butterfat test and average test of nonfat milk solids of milk delivered by the producer;

* * * * *

15. Section 1004.75 is revised to read as follows:

§ 1004.75 Location differentials to producers and on nonpool milk.

(a) For milk received from producers and from cooperative association handlers pursuant to § 1004.9(c) at a plant located 55 miles or more from the city hall in Philadelphia, PA., and also at least 75 miles from the nearer of the zero milestone in Washington, DC, or the city hall in Baltimore, MD. (all distances to be the shortest highway distance as determined by the market administrator), the weighted average differential price for base milk computed pursuant to § 1004.61(b) shall be reduced 1.5 cents for each 10 miles distance or

fraction thereof that such plant is from the nearest of such basing points.

(b) For purposes of computations pursuant to §§ 1004.71 and 1004.74, the weighted average differential price computed pursuant to § 1004.61(a) shall be reduced at the rate set forth in paragraph (a) of this section applicable at the location of the nonpool plant from which the milk was received, except that the adjusted weighted average differential price shall not be less than zero.

16. Section 1004.76 is amended by changing the reference "1004.60(f)" in paragraph (a)(1)(i) to "1004.60(h)", and revising paragraph (b)(5) to read as follows:

§ 1004.76 Payments by a handler operating a partially regulated distributing plant.

* * * * *

(b) * * *

(5) From the value of such milk at the Class I price, subtract its value at the uniform price computed pursuant to § 1004.62, and add for the quantity of reconstituted skim milk specified in paragraph (b)(3) of this section its value computed at the Class I price less the value of such milk at the Class III price (except that the Class I price and the uniform price shall be adjusted for the location of the nonpool plant and shall not be less than the Class III price).

§ 1004.85 [Amended]

17. In § 1004.85, paragraph (a) is amended by changing the reference "§ 1004.60 (d) and (f)" to "§ 1004.60 (f) and (h)."

18. Section 1004.86 is revised to read as follows:

§ 1004.86 Deductions for marketing services.

(a) Except as set forth in paragraph (b) of this section, each handler, making payments directly to producers for milk (other than milk of his own production) pursuant to § 1004.74(a) shall deduct 5 cents per hundredweight or such lesser amount as the Secretary may prescribe and shall pay such deductions to the market administrator on or before the 20th day after the end of the month. Such money shall be expended by the market administrator to provide market information and to verify or establish the weights, samples and tests of milk of producers who are not receiving such service from a cooperative association; and

(b) In the case of producers for whom the Secretary determines a cooperative association is actually performing the services set forth in paragraph (a) of this section, each handler shall make, in lieu of the deduction specified in paragraph (a) of this section, such deductions from the payments to be made directly to such producer pursuant to § 1004.74(a) as are authorized by such producers on or before the 18th day after the end of each month and pay such deductions to the cooperative rendering such services.

Signed at Washington, DC, on: November 25, 1991.

John E. Frydenlund,

Deputy Assistant Secretary Marketing and Inspection Services.

[FR Doc. 91-28808 Filed 12-2-91; 8:45 am]

BILLING CODE 3410-03-M

NUCLEAR REGULATORY COMMISSION

10 CFR Parts 2, 19, 20, 30, 31, 32, 34, 35, 39, 40, 50, 61 and 70

RIN 3150-AA38

Standards for Protection Against Radiation; Correction

AGENCY: Nuclear Regulatory Commission.

ACTION: Final rule; correction.

SUMMARY: This document corrects a final rule appearing in the **Federal Register** on May 21, 1991 (56 FR 23360), that amended 10 CFR part 20 to include the NRC's revised standards for protection against ionizing radiation. This action is necessary to correct minor printing errors and omissions.

EFFECTIVE DATE: June 20, 1991.

FOR FURTHER INFORMATION CONTACT: Michael T. Lesar, Chief, Rules Review Section, Regulatory Publications Branch, Division of Freedom of Information and Publications Services, Office of Administration, U.S. Nuclear Regulatory Commission, Washington, DC 20555, telephone: 301-492-7758.

1. On page 23360, first column, in the "EFFECTIVE DATE" entry, insert "on June 20, 1991." in place of "(30 days after publication in the **Federal Register**)."

§ 20.1005 [Corrected]

2. On page 23395, second column, in the second line of § 20.1005(a), the "(b)" between "." and "One" begins a new paragraph and should be placed one line down and indented.

§ 20.1302 [Corrected]

3. On page 23398, second column, in the eighth line of § 20.1302(c), "aerosal" should read "aerosol."

§ 20.2401 [Corrected]

4. On page 23408, third column, in the fourth line of § 20.2401(c), "quilty" should read "guilty."

Appendix B to §§ 20.1001–20.2401 [Corrected]

5. On page 23409, third column, in the twelfth line of the Introduction to appendix B to §§ 20.1001–20.2401, add "for D" between "days," and "for."

6. On page 23410, in the last line of the first column, "/ALI_{ins})" should read "/ ALI_{ns})."

Appendix C to §§ 20.1001–20.2401 [Corrected]

7. On page 23468, in footnote 1 of appendix C to § 20.1001–20.2401, in the third column, "wμCi," which appears twice in line 6 and once in line 9, should read "μCi."

§ 31.5 [Corrected]

8. On page 23471, in the last two lines of amendatory instruction 21 (§ 31.5), "20.1201 and 20.1202" should read "20.2201 and 20.2202."

§ 31.7 [Corrected]

9. On page 23471, in the last two lines of amendatory instruction 22 (§ 31.7), "20.1201 and 20.1202" should read "20.2201 and 20.2202."

§ 31.10 [Corrected]

10. On page 23471, in the last line of amendatory instruction 23 (§ 31.10(b)(1)), "20.1001" should read "20.2001."

11. On page 23471, in the last line of amendatory instruction 24 (§ 31.10(b)(3)), "20.1001, 20.1201, and 20.1202" should read "20.2001, 20.2201, and 20.2202."

§ 31.11 [Corrected]

12. On page 23471, in the last line of amendatory instruction 25 (§ 31.11(c)(5)), "20.1001" should read "20.2001."

13. On page 23471, in the last line of amendatory instruction 26 (§ 31.11(f)), "20.1001, 20.1201, and 20.1202" should read "20.2001, 20.2201, and 20.2202."

§ 50.73 [Corrected]

14. On page 23474, first column, in § 50.73(a)(2)(ix), "20.405(a)(5)" should read "20.405(a)(1)(v)" and "20.1203(a)(3)" should read "20.2203(a)(3)."

§ 61.52 [Corrected]

15. On page 23474, in the last line of amendatory instruction 61 (§ 61.52), "20.301 and 20.302" should read "20.1301 and 20.1302."

Dated at Rockville, Maryland the 25th day of November, 1991.

For the Nuclear Regulatory Commission.

Donnie H. Grimsley,

Director, Division of Freedom of Information and Publications Services, Office of Administration.

[FR Doc. 91-28805 Filed 12-2-91; 8:45 am]

BILLING CODE 7950-01-M

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 91-NM-230-AD; Amdt. 39-8106; AD 91-25-06]

Airworthiness Directives; Boeing Model 737-300, 737-400, and 737-500 Series Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD) that is applicable to certain Boeing Model 737-300, 737-400, and 737-500 series airplanes. This amendment requires inspection of each thrust reverser auxiliary track, track liner, and slider fitting; and repair or replacement, if necessary. This action is prompted by two recent in-flight incidents in which a thrust reverser translating sleeve panel separated from the airplane. This condition, if not corrected, could result in separation of the sleeve panel and subsequent damage to the airplane control surfaces and/or fuselage, with possible loss of flight control capability or cabin pressure.

DATES: Effective December 18, 1991.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of December 18, 1991.

ADDRESSES: The applicable service information may be obtained from Boeing Commercial Airplane Group, P.O. Box 3707, Seattle, Washington 98124. This information may be examined at the FAA, Northwest Mountain Region, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington; or at the Office of the Federal Register, 1100 L Street NW., room 8401, Washington, DC.

FOR FURTHER INFORMATION CONTACT: Mr. Bernard M. Gonzalez, Seattle Aircraft Certification Office, Propulsion Branch, ANM-140S; telephone (206) 227-2682. Mailing address: FAA, Northwest Mountain Region, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington 98055-4056.

SUPPLEMENTARY INFORMATION: Recently, a Boeing Model 737-300 was involved in an incident in which a thrust reverser translating sleeve panel broke loose and impacted the airplane wing, fuselage, and the vertical and horizontal stabilizers. Several cabin windows were struck by the panel; a window seal was damaged, resulting in air leakage. In a previous incident, a portion of the No. 1 engine left-hand thrust reverser sleeve separated inflight without impacting the airplane. The failure of this panel has been attributed to premature wear of the thrust reverser auxiliary track liners and slider fittings. Such premature wear reduces slider engagement in the track until the slider falls out of the track, which may result in the separation of the translating sleeve. This condition, if allowed to exist, could result in damage to the airplane control surfaces or damage to the fuselage, with possible loss of flight control capability or cabin pressure.

The FAA has reviewed and approved a Boeing Service Letter Number 737-SL-78-22 (as sent by telex M-7272-91-7201), dated November 6, 1991, which describes procedures for inspections of each lower thrust reverser auxiliary track liner and slider fitting to determine the ability of the slider to remain in the track. In addition, the FAA has reviewed and approved Boeing Service Bulletin 737-78-1048, Revision 1, dated February 22, 1990, which describes procedures for inspection of each upper and lower thrust reverser auxiliary track, the liners, and slider fittings for wear; replacement of the liner; and, if necessary, rework or replacement of slider fittings and the auxiliary tracks.

Since this condition is likely to exist or develop on other airplanes of the same type design, this AD requires repetitive inspections of the thrust reverser auxiliary tracks, liners, and slider fittings, in accordance with Boeing Service Letter Number 737-SL-78-22. This AD also requires replacement of the track liners and, if necessary, repair or replacement of the slider fittings and auxiliary tracks, in accordance with Boeing Service Bulletin 737-78-1048, Revision 1. Once the replacement of the track liners is accomplished, the repetitive inspections may be terminated.

Since a situation exists that requires immediate adoption of this regulation, it is found that notice and public procedure hereon are impracticable, and good cause exists for making this amendment effective in less than 30 days.

This is considered interim action. The FAA intends to initiate further rulemaking action to require the replacement of the thrust reverser auxiliary track liner (in accordance with Boeing Service Bulletin 737-78-1048, Revision 1, dated February 22, 1990) on all affected Model 737 series airplanes. However, the proposed compliance time for replacement is sufficiently long so that notice and public comment will not be impracticable.

The regulations adopted herein will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government. Therefore, in accordance with Executive Order 12612, it is determined that this final rule does not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

The FAA has determined that this regulation is an emergency regulation and that it is not considered to be major under Executive Order 12291. It is impracticable for the agency to follow the procedures of Executive Order 12291 with respect to this rule since the rule must be issued immediately to correct an unsafe condition in aircraft. It has been determined further that this action involves an emergency regulation under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979). If it is determined that this emergency regulation otherwise would be significant under DOT Regulatory Policies and Procedures, a final regulatory evaluation will be prepared and placed in the Rules Docket. A copy of it, if filed, may be obtained from the Rules Docket.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

Adoption of the Amendment

Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration amends 14 CFR part 39 of the Federal Aviation Regulations as follows:

PART 39—[AMENDED]

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 1354(a), 1421 and 1423; 49 U.S.C. 106(g); and 14 CFR 11.89.

§ 39.13 [Amended]

2. Section 39.13 is amended by adding the following new airworthiness directive:

91-25-06. Boeing: Amendment 39-8106. Docket No. 91-NM-230-AD.

Applicability: Model 737-300, 737-400, and 737-500 series airplanes; as listed in Boeing Service Bulletin 737-78-1048, Revision 1, dated February 22, 1990; certificated in any category.

Compliance: Required as indicated, unless previously accomplished.

To prevent structural damage to the airplane as a result of separation of the thrust reverser translating sleeve due to worn auxiliary track liners and slider fittings, accomplish the following:

(a) Within 14 days after the effective date of this AD, inspect each lower thrust reverser auxiliary track, liner, and slider fittings to determine the ability of the slider to remain in the track, in accordance with the Accomplishment Instructions of Boeing Alert Service Letter Number 737-SL-78-22 (Telex M-7272-91-7201), dated November 6, 1991. Repeat this inspection thereafter at intervals not to exceed 1,500 hours, 750 hours, or 250 hours time-in-service, as determined by percent engagement of the lower auxiliary track slider, and as specified in the service letter. As a result of this inspection, accomplish the following, as applicable:

(1) If the slider can be pulled out of the track in both the deployed and stowed position, prior to further flight, replace the track liner and, if applicable, replace or repair the slider fittings and the auxiliary track, in accordance with Boeing Service Bulletin 737-78-1048, Revision 1, dated February 22, 1990.

(2) If the slider can be pulled out of the track in only the deployed position, prior to further flight, reinsert the slider in the track and deactivate the thrust reverser in accordance with Chapter 78 of Boeing Document D6-32545, "Boeing 737 Dispatch Deviations Procedures Guide," dated June 14, 1991.

(3) If the slider can not be pulled out of the track in either the deployed or stowed positions, record the percent engagement of the sliders in the lower auxiliary tracks, and repeat the inspection at the specified intervals in accordance with the accomplishment instructions of Boeing Alert Service Letter 737-SL-78-22 (Telex M-7272-91-7201), dated November 6, 1991.

(b) Accomplishment of the replacement of the auxiliary track liner and, if applicable, rework or replacement of the slider fittings and the auxiliary tracks, in accordance with Boeing Service Bulletin 737-78-1048, Revision 1, dated February 22, 1990, constitutes terminating action for the inspection requirements of paragraph (a) of this AD.

(c) An alternative method of compliance or adjustment of the compliance time, which provides an acceptable level of safety, may be used when approved by the Manager, Seattle Aircraft Certification Office (ACO), FAA, Transport Airplane Directorate. The request shall be forwarded through an FAA Principal Maintenance Inspector, who may concur or comment and then send it to the Manager, Seattle ACO.

(d) Special flight permits may be issued in accordance with FAR 21.197 and 21.199 to operate airplanes to a base in order to comply with the requirements of this AD.

(e) The inspections, repairs, and modifications shall be done in accordance with Boeing Alert Service Letter 737-SL-78-22 (sent to operators as Telex M-7272-91-7201), dated November 6, 1991; and Boeing Service Bulletin 737-78-1048, Revision 1, dated February 22, 1990, which contains the following list of effective pages:

Page No.	Revision level	Date
1-4	1	February 22, 1990.
5-44	(original)	February 22, 1989.

The deactivation procedures shall be done in accordance with Chapter 78 of Boeing Document D6-32545, "Boeing 737 Dispatch Deviations Procedures Guide," dated June 14, 1991, which includes the following list of effective pages:

Page No.	Date
2.78-1.0, 2.78-1.2, 2.78-2.0, 2.78-3.0, 2.78-4.0, 2.78-6.0, 2.78-7.0.	June 14, 1991
2.78-1.1	May 31, 1990.
2.78-5.0	August 17, 1989.

This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from Boeing Commercial Airplane Group, P.O. Box 3707, Seattle, Washington 98124. Copies may be inspected at the FAA, Northwest Mountain Region, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington, or at the Office of the Federal Register, 1100 L Street NW., room 8401, Washington, DC.

(f) This amendment (39-8106), AD 91-25-06, becomes effective December 18, 1991.

Issued in Renton, Washington, on November 19, 1991.

Darrell M. Pederson,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 91-28944 Filed 12-2-91; 8:45 am]

BILLING CODE 4910-13-M

14 CFR Part 39

[Docket No. 91-NM-114-AD; Amdt. 39-8097; AD 91-24-11]

Airworthiness Directives; Boeing Model 727 Series Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to certain Boeing Model 727 series airplanes, which requires inspection for cracks and web separation of the body station (BS) 870 terminal fitting, cold working certain fastener holes, and repair or replacement of the fitting, if necessary. This amendment is prompted by reports of cracks and web separations of the BS 870 terminal fitting. This condition, if not corrected, could result in failure of the fitting and depressurization of the airplane.

DATES: Effective January 7, 1992.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of January 7, 1992.

ADDRESSES: The applicable service information may be obtained from Boeing Commercial Airplane Group, P.O. Box 3707, Seattle, Washington 98124. This information may be examined at the FAA, Northwest Mountain Region, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington; or at the Office of the Federal Register, 1100 L Street NW., room 8401, Washington, DC.

FOR FURTHER INFORMATION CONTACT: Ms. Kathi N. Ishimaru, Seattle Aircraft Certification Office, Airframe Branch, ANM-120S; telephone (206) 227-2778. Mailing address: FAA, Northwest Mountain Region, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington 98055-4056.

SUPPLEMENTARY INFORMATION: A proposal to amend part 39 of the Federal Aviation Regulations to include an airworthiness directive, applicable to Boeing Model 727 series airplanes, which requires inspection for cracks and web separation of the body station (BS) 870 terminal fitting, cold working of certain fastener holes, and repair or replacement of fitting, was published in the **Federal Register** on July 2, 1991 (56 FR 30350).

Interested persons have been afforded an opportunity to participate in the making of this amendment. Due consideration has been given to the comments received.

One commenter concurred with the provisions of the proposed AD.

One commenter requested that affected operators be permitted to install "Hi-Tigue" type fasteners in lieu of cold working the fastener holes. The FAA cannot concur because neither data to support the request nor the reasoning for the request were submitted.

One commenter requested that the proposed rule be withdrawn because less than 2% of the affected airplanes have been identified as having problems

with the structure. The FAA does not concur. The FAA has determined that the addressed unsafe condition is an airworthiness problem that is likely to exist or develop on other airplanes of the same type design. There is no reason to believe that the cracks and web separations reported on eight airplanes will not exist on these other airplanes since their BS 870 terminal fitting installations are identical in design.

One commenter requested that the proposed rule be withdrawn because depressurization would develop slowly and, under normal maintenance procedures, the problem would be identified and corrected in a timely manner. The FAA does not concur because the stress corrosion crack growth rate is variable and the depressurization may not develop slowly.

One commenter requested that the repetitive inspection interval for uncracked fittings be reduced from the proposed 6,000 flight cycles to 3,000 flight cycles. The commenter based this request on its understanding of the nature of 7079 material and its tendency for stress corrosion cracking. The FAA does not concur. In developing the appropriate compliance time, the FAA considered the service experience of components made of 7079 material as installed in various transport airplane models, as well as the size of cracking that the specific required inspections are capable of detecting. After consideration of all the available information, the FAA cannot conclude that a reduction of the proposed compliance time, without prior notice and opportunity for comment, is warranted. The FAA has determined that the proposed 6,000-flight cycle inspection interval is appropriate in order to detect corrosion stress cracking in a timely manner.

One commenter requested that the FAA reconsider the advisability of repeated removal of the fasteners for inspection as would be required by the AD. The FAA inferred that the commenter wanted to eliminate the possibility of damage to the part during fastener removal. The FAA has re-evaluated the requirement for fastener removal and has determined that the "Hi-Lok" fasteners may be removed without damage to the part. Consequently, the FAA has determined that the fastener removal described by the proposed inspection procedure (i.e., Boeing Service Bulletin 727-53-0194, dated November 8, 1990) must be retained in the final rule.

Two commenters requested that the requirement for cold working of 7079-T6 material be eliminated. These commenters contended that the effects of cold working are primarily directed at preventing fatigue cracking; however, its effect on preventing the addressed stress corrosion cracking is questionable. The FAA does not concur with the request. The proposed light cold working will produce a compressive stress on the inside diameter of the hole which will combat the tensile stress required for stress corrosion cracking to occur.

One commenter requested that the proposed inspection interval of 6,000 flight cycles or 3 years be changed to only 6,000 flight cycles because it would be easier to control scheduling if the inspection interval were based on flight cycles. The FAA does not concur. Stress corrosion crack growth rate is variable and not completely dependent upon cyclic loading. The FAA has determined that both calendar and flight-cycle intervals are necessary.

Two commenters requested that the proposed removal of the weather caulking be deleted. One commenter stated that the removal of caulking materials may lead to inadvertent damage of the terminal fitting. This commenter pointed out that any required visual inspection would be of little value because the skin gap exposed after caulking is removed is so small that it will not allow a good visual inspection of the terminal fitting. The FAA concurs and has revised the final rule to delete the requirement.

Two commenters requested that proposed paragraph (b) be revised to increase the repetitive inspection interval if certain repairs have been accomplished. One commenter suggested that such an increase should be permitted if oversizing of the fastener holes removes the cracks. Another commenter requested that such an increase be permitted if repairs of cracks are limited to the outboard flange. Upon further consideration, the FAA concurs that, in certain cases, an increase in the inspection interval is warranted. If an outboard flange crack is repaired by oversizing the fastener holes, the crack is eliminated; if an external doubler is used to repair the outboard flange cracks, the strength of the part is restored. The FAA has determined that the interval for repetitive inspections subsequent to these types of repairs may be increased from the proposed 3,000 flight cycles or 18 months, to 6,000 flight cycles or 3 years without compromising safety. The final rule has been changed accordingly.

One commenter requested that paragraph (d) of the proposed rule be changed to specify that the continued inspection after partial replacement only applies to the area of the fitting affected by Boeing Service Bulletin 727-53-0194. The FAA does not concur that the change is necessary. The AD already specifies that unreplaced portions must continue to be inspected in accordance with the AD. There is no added benefit to include the requested words.

One commenter requested that paragraph (e) of the proposed rule specify Boeing Service Bulletin 727-53-0116 in lieu of Boeing Service Bulletin 727-53-0194, as the service document relative to accomplishment of the terminating action. The FAA does not concur that the requested change is necessary. There is no benefit to specifying a different and separate document, since both documents refer to the same procedure for replacing the BS 870 terminal fitting.

One commenter requested that the proposed rule be revised to include an alternative inspection method that does not require fastener removal. The commenter did not request a specific alternative, however. The FAA will consider any alternative methods of compliance submitted in accordance with paragraph (f) of the final rule.

One commenter requested that the requirement for a dye penetrant inspection for web separations be deleted from proposed paragraph (a). This commenter implied that, since this area is subject to visual, eddy current, and ultrasonic inspection methods, a dye penetrant inspection would be redundant. After further consideration, the FAA concurs with the commenter. The ultrasonic inspection for web separations at the lightening holes will identify the presence of cracks in a timely manner. The final rule has been changed to delete the requirement for the dye penetrant inspection.

One commenter stated that the removal of fasteners to inspect for cracks should not be required since an ultrasonic inspection is performed. The FAA does not concur. The high frequency eddy current inspection of the fastener holes will detect very small cracks not detectable using ultrasonic methods. In addition, the ultrasonic inspection's main purpose is to detect web separations that do not originate from fastener holes.

After careful review of the available data, including the comments noted above, the FAA has determined that air safety and the public interest require the adoption of the rule with the changes previously described. The FAA has determined that these changes will neither increase the economic burden on any operator nor increase the scope of the rule.

There are approximately 800 Model 727 series airplanes of the affected design in the worldwide fleet. It is estimated that 640 airplanes of U.S. registry will be affected by this AD, that it will take approximately 76 manhours per airplane to accomplish the required actions, and that the average labor cost will be $55 per manhour. Based on these figures, the total cost impact of the AD on U.S. operators is estimated to be $2,675,200.

The regulations adopted herein will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government. Therefore, in accordance with Executive Order 12612, it is determined that this final rule does not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

For the reasons discussed above, I certify that this action (1) is not a "major rule" under Executive Order 12291; (2) is not a "significant rule" under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and (3) will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act. A final evaluation has been prepared for this action and is contained in the Rules Docket. A copy of it may be obtained from the Rules Docket.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporated by reference, Safety.

Adoption of the Amendment

Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration amends 14 CFR part 39 of the Federal Avaition Regulation as follows:

PART 39—[AMENDED]

1. The authority citation Part 39 continues to read as follows:

Authority: 49 U.S.C. 1354(a), 1421 and 1423; and 14 CFR 11.89.

§ 39.13 [Amended]

2. Section 39.13 is amended by adding the following new airworthiness directive:

91-24-11. Boeing: Amendment 39-8097. Docket No. 91-NM-114-AD.

Applicability: Model 727 series airplanes, line numbers 001 through 875, certificated in any category.

Compliance: Required as indicated, unless previously accomplished.

To prevent failure of the body station (BS) 870 terminal fitting and depressurization of the airplane, accomplish the following:

(a) Prior to the accumulation of 25,000 total flight cycles or within the next 3,000 flight cycles after the effective date of this AD, whichever occurs later, conduct visual, eddy current, and ultrasonic inspections of the body station (BS) 870 terminal fitting for cracks and web separations, in accordance with Figure 1 of Boeing Service Bulletin 727-53-0194, dated November 8, 1990. During the initial inspection, rework uncracked fastener holes and install oversized fasteners, in accordance with Figure 1 of the service bulletin.

(b) If cracks or separations are found, prior to further flight, repair the BS 870 terminal fitting in accordance with Boeing Service Bulletin 727-53-0194, dated November 8, 1990. After repairs, repeat the inspection requirements of paragraph (a) of this AD as follows:

(1) For airplanes on which outboard flange cracks are removed by oversizing the fastener holes, repeat the inspections at intervals not to exceed 6,000 flight cycles or 3 years, whichever occurs first.

(2) For airplanes on which the external doubler is used to repair only outboard flange cracks, repeat the inspections at intervals not to exceed 6,000 flight cycles or 3 years, whichever occurs first.

(3) For airplanes on which the external doubler is used to repair either web separations, or web separations and outboard flange cracks, repeat the inspections at intervals not to exceed 3,000 flight cycles or 18 months, whichever occurs first.

(c) If no cracks or separations are found, repeat the inspection requirements of paragraph (a) of this AD at intervals not to exceed 6,000 flight cycles or 3 years, whichever occurs first.

(d) The partial replacement of the body station (BS) 870 terminal fitting in accordance with Boeing Service Bulletin 727-53-0194, dated November 8, 1990, constitutes termination action for the inspection requirements of this AD, for the replaced portion of the fitting. Unreplaced portions must continue to be inspected in accordance with this AD.

(e) The complete replacement of the body station (BS) 870 terminal fitting in accordance with Boeing Service Bulletin 727-53-0194, dated November 8, 1990, constitutes terminating action for the inspection requirements this AD.

(f) An alternative method of compliance or adjustment of the compliance time, which provides an acceptable level of safety, may be used when approved by the Manager, Seattle Aircraft Certification Office (ACO), FAA, Transport Airplane Directorate.

Note: The request should be forwarded through an FAA Principal Maintenance Inspector, who may concur or comment and then send it to the Manager, Seattle, ACO.

(g) Special flight permits may be issued in accordance with FAR 21.197 and 21.199 to operate airplanes to a base in order to comply with the requirements of this AD.

(h) The inspection and repair requirements shall be done in accordance with Boeing Service Bulletin 727-53-1094, dated November 8, 1990. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from Boeing Commercial Airplane Group, P.O. Box 3707, Seattle, Washington 98124. Copies may be inspected at the FAA, Northwest Mountain Region, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington; or at the Office of the Federal Register, 1100 L Street NW., room 8401, Washington, DC.

This amendment (39-8097, AD 91-24-11) becomes effective January 7, 1992.

Issued in Renton, Washington, on November 5, 1991.

Darrell M. Pederson,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 91-28947 Filed 12-2-91; 8:45 am]

BILLING CODE 4910-13-M

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14 CFR Part 39

[Docket No. 91-NM-109-AD; Amdt. 39-8079; AD 91-23-10]

Airworthiness Directives; Boeing Model 747-400 Series Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to certain Boeing Model 747-400 series airplanes, which requires inspection, repair if necessary, and modification of the advanced cabin entertainment and service system (ACESS) wire bundle installation. This amendment is prompted by reports of chafed wiring resulting in short circuits which led to burned wire bundles. This condition, if not corrected, could result in smoke and fire in the passenger cabin.

DATES: Effective January 7, 1992.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of January 7, 1992.

ADDRESSES: The applicable service information may be obtained from The Boeing Commercial Airplane Group, P.O. Box 3707, Seattle, Washington 98124. This information may be examined at the FAA, Northwest Mountain Region, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington; or at the Office of the Federal Register, 1100 L Street NW., room 8401, Washington, DC.

FOR FURTHER INFORMATION CONTACT: Mr. Stephen S. Oshiro, Seattle Aircraft Certification Office, System and

Equipment Branch, ANM-130S; telephone (206) 227-2793. Mailing address: FAA, Northwest Mountain Region, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington 98055-4056.

SUPPLEMENTARY INFORMATION: A proposal to amend part 39 of the Federal Aviation Regulations to include an airworthiness directive, applicable to certain Boeing Model 747-400 series airplanes, which requires the inspection, repair if necessary, and modification of the ACESS wire bundle installation, was published in the Federal Register on June 24, 1991 (56 FR 28727).

Interested persons have been afforded an opportunity to participate in the making of this amendment. Due consideration has been given to the comments received.

One commenter supported the proposed AD.

The airplane manufacturer recommended that the final rule be written to reflect the latest version of the pertinent service bulletin. The FAA concurs. Since issuance of the Notice, the FAA has reviewed and approved Boeing Alert Service Bulletin 747-23A2241, Revision 3, dated September 5, 1991, which adds optional repair instructions and contains clarifying changes. The FAA has determined that this revision should be identified as the appropriate source of technical data, and has revised the final rule accordingly.

The Air Transport Association (ATA), on behalf of one of its member operators, was concerned that the airplane manufacturer would not be able to provide a certain required parts kit within the proposed compliance time. The ATA requested that the FAA adjust the compliance time accordingly. The FAA does not concur that an increase in compliance time is needed. The FAA has contacted the manufacturer and was informed that, as of September 5, 1991, ample parts kits are on hand and available to operators.

After careful review of the available data, including the comments noted above, the FAA has determined that air safety and public interest require the adoption of the rule with the change previously described. The FAA has determined that this change will neither increase the economic burden on any operator nor increase the scope of this AD.

There are approximately 65 Model 747-400 series airplanes of the affected design in the worldwide fleet. It is estimated that 10 airplanes of U.S. registry will be affected by this AD, that it will take approximately 150 manhours per airplane to accomplish the required actions, and that the average labor cost will be $55 per manhour. Based on these figures, the total cost impact of the AD on U.S. operators is estimated to be $82,500.

The regulations adopted herein will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government. Therefore, in accordance with executive order 12612, it is determined that this final rule does not have sufficient federalism implications to warrant the preparation of a federalism Assessment.

For the reasons discussed above, I certify that this action (1) is not a "major rule" under Executive Order 12291; (2) is not a "significant rule" under DOT Regulatory Policies and procedures (44 FR 11034, February 26, 1979); and (3) will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act. A final evaluation has been prepared for this action and is contained in the Rules Docket. A copy of it may be obtained from the Rules Docket.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

Adoption of the Amendment

Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration amends 14 CFR part 39 of the Federal Aviation Regulations as follows:

PART 39—[AMENDED]

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 1354(a), 1421; 1423; 49 U.S.C. 106(g); and 14 CFR 11.89.

§ 39.13 [Amended]

2. Section 39.13 is amended by adding the following new airworthiness directive:

91-23-10. Boeing; Amendment 39-8079. Docket No. 91-NM-109-AD.

Applicability: Model 747-400 series airplanes, listed in Boeing Alert Service Bulletin 747-23A2241, Revision 3, dated September 5, 1991, certificated in any category.

Compliance: Required as indicated, unless previously accomplished.

To prevent the occurrence of smoke and fire in the passengers cabin, accomplish the following:

(a) Within 12 months after the effective date of this AD, accomplish the following in the main and upper decks:

(1) Inspect the advanced cabin entertainment and service system (ACESS) wire bundle installation at the dado panel near sidewall disconnect for chafing and wear in accordance with Boeing Alert Service Bulletin 747-23A2241, Revision 3, dated September 5, 1991.

(i) If chafing or wear is found, prior to further flight, repair or replace the ACESS cable and install teflon expandable sleeving in accordance with the service bulletin.

(ii) If no chafing or wear is found, install teflon expandable sleeving on the ACESS cable in accordance with the service bulletin.

(2) Inspect all advanced cabin entertainment and service system (ACESS) seat to seat cables for chafing and wear in accordance with Boeing Alert Service Bulletin 747-23A2241, Revision 3, dated September 5, 1991.

(i) If chafing or wear is found, prior to further flight, repair or replace the ACESS cable, and ensure proper installation in accordance with the service bulletin.

(ii) If no chafing or wear is found, ensure proper cable installation in accordance with the service bulletin.

(3) Modify the ACESS wire bundle installation at the dado panel near each sidewall disconnect in accordance with Boeing Alert Service Bulletin 747-23A2241, Revision 3, dated September 5, 1991.

(b) An alternative method of compliance or adjustment of the compliance time, which provides an acceptable level of safety, may be used when approved by the Manager, Seattle Aircraft Certification Office (ACO), FAA, Transport Airplane Directorate.

Note: The request should be forwarded through an FAA Principal Maintenance Inspector, who may concur or comment and then send it to the Manager, Seattle ACO.

(c) Special flight permits may be issued in accordance with FAR 21.197 and 21.199 to operate airplane to a base in order to comply with the requirements of this AD.

(d) The inspections, repairs, and modifications shall be done in accordance with Boeing Alert Service Bulletin 747-23A2241, Revision 3, dated September 5, 1991, which contains the following list of effective pages:

Page No.	Revision level	Date
1, 4-7, 10, 14-16, 24-26.	3	September 5, 1991.
2, 3, 8-9, 11-13, 17-23.	2	November 1, 1990.

This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from Boeing Commercial Airplane Group, P.O. Box 3707, Seattle, Washington 98124. Copies may be inspected at the FAA, Northwest Mountain Region, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington, or at the Office of the

Federal Register, 1100 L Street NW., room 8401, Washington DC.

This amendment (39-8079, AD 91-23-10) becomes effective January 7, 1992.

Issued in Renton, Washington, on October 22, 1991.

Darrell M. Pederson,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 91-28949 Filed 12-2-91; 8:45am]

BILLING CODE 4910-13-M

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14 CFR Part 39

[Docket No. 91-NM-133-AD; Amdt. 39-8098; AD 91-24-12]

Airworthiness Directives; British Aerospace Model ATP Series Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to certain British Aerospace Model ATP series airplanes, which requires modification and testing of the landing gear hydraulic selector valve. This amendment is prompted by recent reports of friction in the selector valve plunger, requiring increased effort by the flight crew to select the landing gear down. This condition, if not corrected, could result in a gear-up landing.

DATES: Effective January 7, 1992.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the **Federal Register** as of January 7, 1992.

ADDRESSES: The applicable service information may be obtained from British Aerospace, PLC, Librarian for Service Bulletins, P.O. Box 17414, Dulles International Airport, Washington, DC 20041-0414. This information may be examined at the FAA, Northwest Mountain Region, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington; or at the Office of the Federal Register, 1100 L Street, NW., room 8401, Washington, DC.

FOR FURTHER INFORMATION CONTACT: Mr. William Schroeder, Standardization Branch, ANM-113; telephone (206) 227-2148. Mailing address: FAA, Northwest Mountain Region, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington 98055-4056.

SUPPLEMENTARY INFORMATION: A proposal to amend Part 39 of the Federal Aviation Regulations to include a new airworthiness directive, applicable to certain British Aerospace Model ATP series airplanes, which requires modification and testing of the landing gear hydraulic selector valve, was published in the **Federal Register** on August 6, 1991 (56 FR 37317).

Interested persons have been afforded an opportunity to participate in the making of this amendment. Due consideration has been given to the single comment received.

The commenter supported the rule.

After careful review of the available data, including the comment noted above, the FAA has determined that air safety and the public interest require the adoption of the rule as proposed.

It is estimated that 6 airplanes of U.S. registry will be affected by this AD, that it will take approximately 6 manhours per airplane to accomplish the required actions, and that the average labor cost will be $55 per manhour. Based on these figures, the total cost impact of the AD on U.S. operators is estimated to be $1,980.

The regulations adopted herein will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government. Therefore, in accordance with Executive Order 12612, it is determined that this final rule does not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

For the reasons discussed above, I certify that this action (1) is not a "major rule" under Executive Order 12291; (2) is not a "significant rule" under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and (3) will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act. A final evaluation has been prepared for this action and is contained in the Rules Docket. A copy of it may be obtained from the Rules Docket.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

Adoption of the Amendment

Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration amends 14 CFR part 39 of the Federal Aviation Regulations as follows:

PART 39—[AMENDED]

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 1354(a), 1421 and 1423; 49 U.S.C. 106(g); and 14 CFR 11.89.

§ 39.13 [Amended]

2. Section 39.13 is amended by adding the following new airworthiness directive:

91-24-12. British Aerospace: Amendment 39-8098. Docket 91-NM-133-AD.

Applicability: Model ATP series airplanes, equipped with hydraulic selector valves part number AIR44880 and AIR44882, certificated in any category.

Compliance: Required as indicated, unless previously accomplished.

To prevent a gear-up landing, accomplish the following:

(a) Within 12 months after the effective date of this AD, modify and test the landing gear hydraulic selector valves in accordance with AP Precision Hydraulics Service Bulletin AIR44880-29-01, dated April 1991.

Note: British Aerospace Service Bulletin ATP-29-6, dated April 12, 1991, references AP Precision Hydraulics Service Bulletin AIR44880-29-01, dated April 1991.

(b) An alternative method of compliance or adjustment of the compliance time, which provides an acceptable level of safety, may be used when approved by the Manager, Standardization Branch, ANM-113, FAA, Transport Airplane Directorate.

Note: The request should be forwarded through an FAA Principal Maintenance Inspector, who may concur or comment and then send it to the Manager, Standardization Branch, ANM-113.

(c) Special flight permits may be issued in accordance with FAR 21.197 and 21.199 to operate airplanes to a base in order to comply with the requirements of this AD.

(d) The modification and testing requirements shall be done in accordance with AP Precision Hydraulics Service Bulletin AIR44880-29-01, dated April 1991. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from British Aerospace, PLC, Librarian for Service Bulletins, P.O. Box 17414, Dulles International Airport, Washington, DC 20041-0414. Copies may be inspected at the FAA, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington; or at the Office of the Federal Register, 1100 L Street NW., room 8401, Washington, DC.

This amendment (39-8098, AD 91-24-12) becomes effective January 7, 1992.

Issued in Renton, Washington, on November 5, 1991.

Darrell M. Pederson,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 91-28948 Filed 12-2-91; 8:45 am]

BILLING CODE 4910-13-M

14 CFR Part 39

[Docket No. 91-NM-151-AD; Amdt. 39-8105; AD 91-25-04]

Airworthiness Directives; Garrett Auxiliary Power Division Models TSCP700-4B and TSCP700-5 Auxiliary Power Units (APU), as Installed on, but not Limited to McDonnell Douglas Model DC-10 and KC-10 (Military) Series Airplanes and Airbus Industrie Model A300 Series Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to certain Garrett auxiliary power units (APU), which requires replacement of the high pressure turbine (HPT) containment ring. This amendment is prompted by reports of HPT disc ruptures. This condition, if not corrected, could result in an uncontained HPT disc failure, with fragments of the disc exiting the APU casing and causing damage to the airplane.

DATES: Effective January 7, 1992.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of January 7, 1992.

ADDRESSES: The applicable service information may be obtained from Garrett Airlines Services Division, Technical Publications, Department 65-70, P.O. Box 52170, Phoenix, Arizona 85072-2170. This information may be examined at the FAA, Northwest Mountain Region, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington; or at the Los Angeles Aircraft Certification Office, 3229 East Spring Street, Long Beach, California; or at the Office of the Federal Register, 1100 L Street NW., room 8401, Washington, DC.

FOR FURTHER INFORMATION CONTACT: Mr. Robert Baitoo, Aerospace Engineer, Propulsion Branch, ANM-140L, FAA, Northwest Mountain Region, Transport Airplane Directorate, Los Angeles Aircraft Certification Office, 3229 East Spring Street, Long Beach, California 90806-2425; telephone (213) 988-5245.

SUPPLEMENTARY INFORMATION: A proposal to amend Part 39 of the Federal Aviation Regulations to include an airworthiness directive, applicable to certain Garrett auxiliary power units (APU), which requires replacement of the high pressure turbine (HPT) containment ring, was published in the Federal Register on August 14, 1991 (56 FR 40282).

Interested persons have been afforded an opportunity to participate in the making of this amendment. Due consideration has been given to the comments received.

Two commenters concurred with the proposed rule.

Three commenters requested that the proposed compliance time of 24 months for accomplishing the replacement of the HPT containment ring be increased to 36 months. The reason they cited was limited parts availability. The FAA does not concur. The proposed compliance time of 24 months was developed based on data available to the FAA, including the manufacturer's ability to provide an ample number of required parts, and represents what was determined to be maximum interval of time allowable wherein the replacement could reasonably be accomplished and an acceptable level of safety could be maintained.

Two commenters requested that the compliance time be at the APU next shop visit, to prevent unscheduled removals of APU's. The FAA does not concur. In developing the proposed compliance time, the FAA has determined that the hazard posed by ruptured HPT discs warrants a 24-month compliance time. This compliance time was determined to be appropriate in consideration of the average utilization rate of the affected operators and the availability of required modification parts. Since maintenance schedules may vary from operator to operator, there would be no assurance that the replacement of the HPT containment ring and support would be accomplished during that time.

After careful review of the available data, including the comments noted above, the FAA has determined that air safety and the public interest require the adoption of the rule as proposed.

There are approximately 675 McDonnell Douglas Model DC-10 and KC-10 (military) series airplanes and Airbus Model A300 series airplanes in the worldwide fleet that may be equipped with the affected APU. It is estimated that 304 airplanes of U.S. registry would be affected by this AD, that it would take approximately 130 manhours per airplane to accomplish the required actions, and that the average labor cost would be $55 per manhour. The cost for required parts is approximately $2,000 per airplane. Based on these figures, the total cost impact of the AD on U.S. operators is estimated to be $2,781,600.

The regulations adopted herein will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government. Therefore, in accordance with Executive Order 12612, it is determined that this final rule does not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

For the reasons discussed above, I certify that this action (1) is not a "major rule" under Executive Order 12291; (2) is not a "significant rule" under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and (3) will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act. A final evaluation has been prepared for this action and is contained in the Rules Docket. A copy of it may be obtained from the Rules Docket.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

Adoption of the Amendment

Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration amends 14 CFR part 39 of the Federal Aviation Regulations as follows:

PART 39—[AMENDED]

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 1354(a), 1421 and 1423; 49 U.S.C. 106(g); and 14 CFR 11.89.

§ 39.13 [Amended]

2. Section 39.13 is amended by adding the following new airworthiness directive:

91-25-04. Garrett Auxiliary Power Division: Amendment 39-8105. Docket No. 91-NM-151-AD.

Applicability: Model TSCP700-4B auxiliary power units (APU) prior to serial number 90697, as installed in, but not limited to, McDonnell Douglas Model DC-10 and KC-10 (military) series airplanes; and Model TSCP700-5 APU's prior to serial number 80443, as installed in, but not limited to, Airbus Industrie Model A300 series airplanes; ceritficated in any category.

Compliance: Required within 24 months after the effective date of this AD, unless previously accomplished.

To prevent uncontained high pressure turbine (HPT) disc failures, accomplish the following:

(a) Replace the HPT containment ring, part number (P/N) 976850-1, with P/N 3614975-1; and replace the HPT containment support, P/N 3604274-1, with P/N 3614934-1; in

accordance with the accomplishment instructions in Garrett Service Bulletin TSCP700-49-5892, Revision 2, dated October 10, 1990.

(b) An alternative method of compliance or adjustment of the compliance time, which provides an acceptable level of safety, may be used when approved by the Manager, Los Angeles Aircraft Certification Office (ACO), FAA, Transport Airplane Directorate.

Note: The request should be forwarded through an FAA Principal Maintenance Inspector, who may concur or comment and then send it to the Manager, Los Angeles ACO.

(c) Special flight permits may be issued in accordance with FAR 21.197 and 21.199 to operate airplanes to a base in order to comply with the requirements of this AD.

(d) The replacement requirements shall be done in accordance with Garrett Service Bulletin TSCP700-49-5892, Revision 2, dated October 10, 1990, which contains the following list of effective pages:

Page No.	Revision level	Date
1, 7/8	2	October 10, 1990.
2, 3/4, 5, 6	(Original)	May 14, 1990.
9/10	1	July 3, 1990.

This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from Garrett Airlines Services Division, Technical Publications, Department 65-70, P.O. Box 52170, Phoenix, Arizona 85072-2170. Copies may be inspected at the FAA, Northwest Mountain Region, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington; or at the Los Angeles Aircraft Certification Office, 3229 East Spring Street, Long Beach, California; or at the Office of the Federal Register, 1100 L Street NW., room 8401, Washington, DC.

This amendment (39-8105, AD 91-25-04) becomes effective on January 7, 1992.

Issued in Renton, Washington, on November 14, 1991.

Leroy A. Keith,

Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 91-28946 Filed 12-2-91; 8:45 am]

BILLING CODE 4910-13-M

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14 CFR Part 39

[Docket No. 91-NM-236-AD; Amdt. 39-8107; AD 91-25-05]

Airworthiness Directives; Gulfstream Aerospace Corporation Model G-1159A (G-III) and G-IV Series Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD) that is applicable to certain Gulfstream Model G-1159A (G-III) and G-IV series airplanes. This amendment requires a one-time inspection to detect chafing or damage of the electrical feeder cables located between the power distribution box and the co-pilot's junction box, and repair of chafed or damaged cables, if necessary. This action is prompted by a recent report of a burn-through of insulation in a wire bundle located in a junction box behind the co-pilot seat of a Model G-III airplane; the resultant damage caused the loss of power to all of the airplane's primary avionics systems. This condition, if not corrected, could result in avionics system failures which would severely inhibit the ability of the flight crew to deal with adverse operating conditions, as well as their ability to conduct a safe flight and landing.

DATES: Effective December 18, 1991.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of December 18, 1991.

ADDRESSES: The applicable service information may be obtained from Gulfstream Aerospace Corporation, P.O. Box 2206, M/S D-10, Savannah, Georgia 31402-9980. This information may be examined at the FAA, Northwest Mountain Region, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington; at the FAA, Small Airplane Directorate, Atlanta Aircraft Certification Office, 1669 Phoenix Parkway, suite 210C, Atlanta, Georgia; or at the Office of the Federal Register, 1100 L Street, NW., room 8401, Washington, DC.

FOR FURTHER INFORMATION CONTACT: Mr. James H. Williams, Systems and Equipment Branch, ACE-130A; telephone (404) 991-3020. Mailing address: FAA, Small Airplane Directorate, Atlanta Aircraft Certification Office, 1669 Phoenix Parkway, Suite 210C, Atlanta, Georgia 30349.

SUPPLEMENTARY INFORMATION: The FAA recently received a report of a burn-through of insulation in a wire bundle located below the junction box behind the co-pilot seat on a Model G-III airplane. The resultant damage cause the loss of power to many of the airplane's systems, including both navigation radios, all communication radios, both transponders, the Electronic Flight Instrument System (EFIS), the anti-skid system, the nose wheel steering system, the autopilot/flight director system, and all cockpit lighting. The standby compass, artificial horizon, air speed indicator, and altimeter were the only instruments that remained operative.

Preliminary inspection results have revealed that other Gulfstream Model G-III and G-IV series airplanes have varying amounts of damage to the wire bundle. This wire bundle combines all power to the essential and critical avionics equipment installed on these airplanes. Damage to the wire bundle could result in loss of the avionics equipment capabilities. If not corrected, failure of the avionics system would severely inhibit the ability of the flight crew to deal with adverse operating conditions, as well as their ability to conduct a safe flight and landing.

The FAA has reviewed and approved Gulfstream Alert Customer Bulletins No. 6A (for Model G-III series airplanes) and No. 7A (for Model G-IV series airplanes), both dated October 1, 1991. These service documents describe procedures for conducting a one-time inspection to detect chafing or damage of the electrical feeder cables located between the power distribution box and the co-pilot's junction box, and repair of chafed or damaged cables, if necessary.

Since this condition is likely to exist or develop on other airplanes of the same type design, this AD requires a one-time inspection to detect chafing or damage of the electrical feeder cables located between the power distribution box and the co-pilot's junction box, and repair of chafed or damaged cables, if necessary, in accordance with the service bulletins previously described.

This is considered to be interim action. The manufacturer is currently developing a design modification involving the installation of new wire bundles that separate the functions provided by the essential and critical avionics equipment into independent electrical cables. Once this modification is developed, approved, and available to operators, the FAA may consider further rulemaking to require its installation.

Since a situation exists that requires immediate adoption of this regulation, it is found that notice and public procedure hereon are impracticable, and good cause exists for making this amendment effective in less than 30 days.

The regulations adopted herein will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government. Therefore, in accordance with Executive Order 12612, it is determined that this final rule does not

have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

The FAA has determined that this regulation is an emergency regulation and that it is not considered to be major under Executive Order 12291. It is impracticable for the agency to follow the procedures of Executive Order 12291 with respect to this rule since the rule must be issued immediately to correct an unsafe condition in aircraft. It has been determined further that this action involves an emergency regulation under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979). If it is determined that this emergency regulation otherwise would be significant under DOT Regulatory Policies and Procedures, a final regulatory evaluation will be prepared and placed in the Rules Docket. A copy of it, if filed, may be obtained from the Rules Docket.

List of Subjects in 14 CFR Part 39

Air Transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

Adoption of the Amendment

Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration amends 14 CFR part 39 of the Federal Aviation Regulations as follows:

PART 39—[AMENDED]

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 1354(a), 1421 and 1423; 49 U.S.C. 106(g); and 14 CFR 11.89.

§ 39.13 [Amended]

2. Section 39.13 is amended by adding the following new airworthiness directive:

91-25-05. Gulfstream Aerospace Corporation: Amendment 39-8107. Docket No. 91-NM-236-AD.

Applicability: Model G-1159A (G-III) series airplanes, serial numbers 357, and 402 through 498; and Model G-IV series airplanes, serial numbers 1000 through 1180; certificated in any category.

Compliance: Required as indicated, unless previously accomplished.

To prevent avionics system failures which would severely inhibit the ability of the flight crew to deal with adverse operating conditions, as well as their ability to conduct a safe flight and landing, accomplish the following:

(a) Within 25 hours time-in-service after the effective date of this AD, perform a one-time inspection to detect chafing or damage of the electrical feeder cable located between the power distribution box and the co-pilot's junction box, in accordance with Gulfstream Alert Customer Bulletins No. 6A (for Model G-III series airplanes), or No. 7A (for Model G-IV series airplanes), both dated October 1, 1991, as applicable.

(b) If chafing or damage is detected as a result of the inspection required by paragraph (a) of this AD, prior to further flight, repair the electrical feeder cable in accordance with a manner approved by the Manager, Atlanta Aircraft Certification Office (ACO), FAA, Small Airplane Directorate.

(c) An alternative method of compliance or adjustment of the compliance time, which provides an acceptable level of safety, may be used when approved by the Manager, Atlanta Aircraft Certification Office (ACO), FAA, Small Airplane Directorate. The request should be forwarded through an FAA Principal Maintenance or Avionics Inspector, who may concur or comment and then send it to the Manager, Atlanta ACO.

(d) Special flight permits may be issued in accordance with FAR 21.197 and 21.199 to operate airplanes to a base in order to comply with the requirements of this AD.

(e) The inspection requirements shall be done in accordance with Gulfstream Alert Customer Bulletin No. 6A, dated October 1, 1991, or Gulfstream Alert Customer Bulletin No. 7A, dated October 1, 1991, as applicable. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from Gulfstream Aerospace Corporation, P.O. Box 2206, M/S D-10, Savannah, Georgia 31402-9980. Copies may be inspected at the FAA, Transport Airplane Directorate, 1601 Lind Avenue SW, Renton, Washington; at the FAA, Small Airplane Directorate, Atlanta Aircraft Certification Office, 1669 Phoenix Parkway, suite 210C, Atlanta, Georgia; or at the Office of the Federal Register, 1100 L Street, NW., room 8401, Washington, DC.

(f) This amendment (39-8107), AD 91-25-05 becomes effective December 18, 1992.

Issued in Renton, Washington, on November 18, 1991.

Leroy A. Keith,

Manager, Transport Airplane Directorate Aircraft Certification Service.

[FR Doc. 91-28943 Filed 12-2-91; 8:45 am]

BILLING CODE 4910-13-M

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14 CFR Part 39

[Docket No. 91-NM-198-AD; Amdt. 30-8099; AD 91-21-51]

Airworthiness Directives; Lockheed Model L-1011-385 Series Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY This action publishes in the Federal Register and makes effective as to all persons an amendment adopting Airworthiness Directive (AD) 91-21-51, which was previously made effective as to all known U.S. owners and operators of Lockheed Model L-1011-385 series airplanes by individual telegrams. This AD requires inspections of fuselage station (FS) 983 main frame (left and right sides), and repair, if necessary. This action is prompted by reports of cracks found in the left and right sides of FS 983 main frame, below the level of the cabin floor. Cracks in the fuselage frame, if not detected and repaired, could result in reduced structural integrity of the fuselage.

DATES: Effective December 18, 1991, as to all persons except those persons to whom it was made immediately effective by telegraphic AD 91-21-51, issued October 7, 1991, which contained this amendment.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of December 18, 1991.

ADDRESSES: The applicable service information may be obtained from Lockheed Aeronautical Systems Company-Georgia, Attn: Commercial and Customer Support, Dept. 73-05, Zone 0199, 86 South Cobb Drive, Marietta, Georgia 30063. This information may be examined at the FAA, Northwest Mountain Region, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington; at the FAA, Small Airplane Directorate, Atlanta Aircraft Certification Office, 1669 Phoenix Parkway, suite 210C, Atlanta, Georgia; or at the Office of the Federal Register, 1100 L Street NW., room 8401, Washington, DC.

FOR FURTHER INFORMATION CONTACT: Mr. Tom Peters, Atlanta Aircraft Certification Office, Flight Test Branch, ACE-115A; telephone (404) 991-3915. Mailing address: FAA, Central Region, Atlanta Aircraft Certification Office, 1669 Phoenix Parkway, suite 210C, Atlanta, Georgia 30349.

SUPPLEMENTARY INFORMATION: On October 7, 1991, the FAA issued telegraphic AD 91-21-51, applicable to Lockheed Model L-1011-385 series airplanes, which requires inspections of fuselage station (FS) 983 main frame (left and right sides, and repair, if necessary. That AD also requires operators to submit a report of the findings of the inspections to the FAA. That action was prompted by a report from an operator which discovered a six inch long crack in the left side of FS 983 main frame, which was located approximately eight inches below the level of the cabin floor. Subsequent examination of the right side of FS 983 main frame revealed a shorter, but similarly located crack. Another airplane was inspected, and a similar crack was found in the left frame. These

cracks appear to have been caused by stress corrosion. Cracks in the fuselage frame, if not detected and repaired, could result in reduced structural integrity of the fuselage.

The FAA has reviewed and approved Lockheed Service Bulletin 093-53-264, dated October 4, 1991, which describes procedures to perform an inspection of FS 983 main frame (left and right sides), and repair, if necessary.

This is considered to be interim action until final action is identified, at which time the FAA may consider further rulemaking.

Since it was found that immediate corrective action was required, notice and public procedure thereon were impracticable and contrary to the public interest, and good cause existed to make the AD effective immediately by individual telegrams issued on October 7, 1991, to all known U.S. owners and operators of Lockheed Model L-1011-385 series airplanes. These conditions still exist, and the AD is hereby published in the **Federal Register** as an amendment to § 39.13 of part 39 of the Federal Aviation Regulations (FAR) to make it effective as to all persons.

The regulations adopted herein will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government. Therefore, in accordance with Executive Order 12612, it is determined that this final rule does not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

The Federal Aviation Administration has determined that this regulation is an emergency regulation and that it is not considered to be major under Executive Order 12292. It is impracticable for the agency to follow the procedures of Executive Order 12291 with respect to this rule since the rule must be issued immediately to correct an unsafe condition in aircraft. It has been determined further that this action involves an emergency regulation under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979). If it is determined that this emergency regulation otherwise would be significant under DOT Regulatory Policies and Procedures, a final regulatory evaluation will be prepared and placed in the Rules Docket. A copy of it, if filed, may be obtained from the Rules Docket.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation Safety, Incorporation by reference, Safety

Adoption of the Amendment

Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration amends 14 CFR part 39 of the Federal Aviation Regulations as follows:

PART 39—[AMENDED]

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 1354(a), 1421 and 1423; 49 U.S.C. 106(g); and 14 CFR 11.89.

§ 39.13 [Amended]

2. Section 39.13 is amended by adding the following new airworthiness directive.

91-21-51. Lockheed: Amendment 39-8099. Docket No. 91-NM-198-AD.

Applicability: Lockheed Model L-1011-385 series airplanes, certificated in any category.

Compliance: Required as indicated, unless previously accomplished.

To prevent reduced structural integrity of the fuselage, accomplish the follows:

(a) Within 20 days after the effective date of this AD, inspect the left and right sides of fuselage station (FS) 983 main frame from waterline (WL) 175 to WL 200 to detect cracks using a high frequency eddy current procedure in accordance with paragraph A. of the Accomplishment Instructions of Lockheed Service Bulletin 093-53-264, dated October 4, 1991 (hereinafter referred to as "the bulletin"). At the operator's option, the internal inspection required by paragraph (d) below may be used in lieu of the external inspection.

(b) If cracks are found that extend into the main frame caps, prior to further flight, repair in a manner approved by the Manager, Atlanta Aircraft Certification Office.

(c) Within 7 days after the initial inspection required by paragraph (a) of this AD, submit a report of the inspection results, positive or negative, to the Manager, Atlanta Aircraft Certification Office (ACO), FAA, Small Airplane Directorate, 1669 Phoenix Parkway, suite 210C, Atlanta, Georgia 30349. [Facsimile messages may be sent via telephone number (404) 991-3606.]

(d) Within 60 days after the effective date of this AD, perform an internal visual and eddy current inspection of the FS 983 main frame cap and web in accordance with paragraph B. of the Accomplishment Instructions of the bulletin.

(e) If cracks are found in the following locations prior to further flight, repair in a manner approved by the Manager, Atlanta Aircraft Certification Office:

(1) Any crack extending into the main frames caps;

(2) Any crack extending into the web-to-cap radius;

(1) Any crack extending into a web area outside the shaded area shown in Figure 1, Sheet 3, of the bulletin; or

(4) More than one crack is found within the main frame web area shown in Figure 1, Sheet 3, of the bulletin.

(f) If a single crack is found that is completely contained within the main frame web area shown in Figure 1, Sheet 3, of the bulletin, treat the cracked section of the web with corrosion inhibitor in accordance with the bulletin. Thereafter, perform repetitive inspections, at intervals not to exceed 90 days, using the internal inspection procedure required by paragraph (d) of this AD.

(g) If any cracks are found as a result of the inspections required by paragraph (d) or (f) of this AD, within 7 days, submit a report to the manager, Atlanta Aircraft Certification Office (ACO), FAA, Small Airplane Director, 1669 Phoenix Parkway, suite 210C, Atlanta, Georgia 30349. [Facsimile messages may be sent via telephone number (404) 991-3606.]

(h) Information collection requirements contained in this regulation have been approved by the Office of Management and Budget (OMB) under the provisions of the Paperwork Reduction Act of 1980 (Pub. L. 96-511) and have been assigned OMB Control Number 2120-0056.

(i) An alternative method of compliance or adjustment of the compliance time, which provides an acceptable level of safety, may be used when approved by the Manager, Atlanta Aircraft Certification Office (ACO), FAA, Small Airplane Directorate.

Note: The request should be forwarded through an FAA Principal Maintenance Inspector, who may concur or comment and then send it to the Manage, Atlanta ACO.

(j) Special flight permits may be issued in accordance with FAR 21.197 and 21.199 to operate airplanes to a base in order to comply with the requirements of this AD.

(k) The inspection and repair requirements shall be done in accordance with Lockheed Service Bulletin 093-53-264, dated October 4, 1991. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from Lockheed Aeronautical Systems Company-Georgia, Attn: Commercial and Customer Support, Dept. 73-05, Zone 0199, 86 South Cobb Drive, Marietta, Georgia 30063. Copies may be inspected at the FAA, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington; or at the FAA, Small Airplane Directorate, Atlanta Aircraft Certification Office, 1669 Phoenix Parkway, suite 210C, Atlanta, Georgia; or at the Office of the Federal Register, 1100 L Street NW., room 8401, Washington, DC.

This amendment (39-8099, AD 91-21-51) becomes effective December 18, 1991 as to all persons, except those persons to whom it was made immediately effective by telegraphic AD 91-21-51, issued October 7, 1991, which contained this amendment.

Issued in Renton, Washington, on November 5, 1991.

Darrell M. Pederson,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 91-28950 Filed 12-2-91; 8:45 am]

BILLING CODE 4910-13-M

14 CFR Part 39

[Docket No. 91-NM-130-AD; Amdt. 39-8091; AD 91-24-05]

Airworthiness Directives; McDonnell Douglas Model DC-9 and DC-9-80 Series Airplanes, Model MD-88 Airplanes, and C-9 (Military) Series Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This amendment supersedes an existing airworthiness directive (AD), applicable to certain McDonnell Douglas Model DC-9 and DC-9-80 series airplanes, and Model MD-88 airplanes, and C-9 (Military) series airplanes, which currently requires replacement of a certain lap belt at the forward cabin attendant double seat. That action was prompted by a report that the outboard attendant lap seat belt connection half can inadvertently be thrown into the lower hinge of the passenger entrance door and obstruct opening of the door. This condition, if not corrected, could result in delayed evacuation of passengers in an emergency situation. This amendment requires inspection of the outboard lap belt assembly at the forward cabin attendant seat installed on additional airplanes, and replacement of the lap belt if it can obstruct the opening of the passenger entrance door.

DATES: Effective January 7, 1992.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the **Federal Register** as of January 7, 1992.

ADDRESSES: The applicable service information may be obtained from McDonnell Douglas Corporation, P.O. Box 1171, Long Beach, California 90801; Attn: Business Unit Manager, Technical Publications & Technical Administrative Support, C1-L5B (54-60). This information may be examined at the FAA, Northwest Mountain Region, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington; or at the Los Angeles Aircraft Certification Office, 3229 East Spring Street, Long Beach, California; or at the Office of the Federal Register, 1100 L Street NW., room 8401, Washington, DC.

FOR FURTHER INFORMATION CONTACT: Walter Eierman, Aerospace Engineer, Los Angeles Aircraft Certification Office, Systems and Equipment Branch, ANM-131L, FAA, Northwest Mountain Region, Transport Airplane Directorate, 3229 East Spring Street, Long Beach, California 90806-2425; telephone (213) 988-5336.

SUPPLEMENTARY INFORMATION: A proposal to amend part 39 of the Federal Aviation Regulations by superseding AD 90-15-02, Amendment 39-6651 (55 FR 28183, July 10, 1990), applicable to DC-9 and DC-9-80 series airplanes, Model MD-88 airplanes, and C-9 (military) series airplanes, was published in the **Federal Register** on August 6, 1991 (56 FR 37319). That action proposed to require inspection of the lap belt assemblies at the forward outboard cabin attendant seat to determine if the seat lap belt connection half can inadvertently be thrown into the lower hinge of the passenger entrance door and, where necessary, replacement of the lap belt. The intent of the proposed requirements is to eliminate the interference with the door hinge.

Interested persons have been afforded an opportunity to participate in the making of this amendment. Due consideration has been given to the comments received.

Two commenters responded to the proposal, both of whom supported it.

Since issuance of the Notice, the FAA has reviewed and approved McDonnell Douglas DC-9 Alert Service Bulletin A25-321, dated August 8, 1991, which describes procedures for inspecting the outboard attendant seat lap belt to determine if the connector or buckle is capable of reaching and interfering with the lower hinge of the passenger entrance door and obstructing the opening of the door, and procedures for necessary correction of discrepancies. The effectivity of this service bulletin specifically addresses those airplanes that were not listed in McDonnell Douglas DC-9 Alert Service Bulletin A25-311, dated January 31, 1990. A note has been added to the final rule to identify this service bulletin A25-321 as an approved alternative method of compliance with this AD.

After careful review of the available data, including the comments noted above, the FAA has determined that air safety and the public interest require the adoption of the rule with the change previously described. The FAA has determined that this change will neither increase the economic burden on any operator nor increase the scope of the AD.

There are approximately 1,793 Model DC-9 series, DC-9-80 series, MD-88, and C-9 (Military) series airplanes of the affected design in the worldwide fleet. It is estimated that 1,085 airplanes of U.S. registry will be affected by this AD, that it will take approximately 0.6 manhour per airplane to accomplish the required actions, and that the average labor cost will be $55 per manhour. Based on these figures, the total cost impact of the AD on U.S. operators is estimated to be $35,805. Where seat belt interference is discovered, an additional $80 per airplane would be required for the cost of the replacement belt.

The regulations adopted herein will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government. Therefore, in accordance with Executive Order 12612, it is determined that this final rule does not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

For the reasons discussed above, I certify that this action (1) is not a "major rule" under Executive Order 12291; (2) is not a "significant rule" under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and (3) will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act. A final evaluation has been prepared for this action and is contained in the Rules Docket. A copy of it may be obtained from the Rules Docket.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

Adoption of the Amendment

Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration amends 14 CFR part 39 of the Federal Aviation Regulations as follows:

PART 39—[AMENDED]

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 1354(a), 1421 and 1423; 49 U.S.C. 106(g); and 14 CFR 11.89.

§ 39.13 [Amended]

2. Section 39.13 is amended by removing Amendment 39-6651 (55 FR 28183, July 10, 1990) and by adding the following new airworthiness directive:

91-24-05. **McDonnell Douglas:** Amendment 39-8091. Docket 91-NM-130-AD. Supersedes AD 90-15-02, Amendment 39-6651.

Applicability: All Model DC-9 and DC-9-80 series airplanes, Model MD-88 airplanes, and C-9 (military) airplanes, certified in any category.

Compliance: Required as indicated, unless previously accomplished.

To prevent the lap belt connector or buckle from jamming the passenger entrance door hinge, accomplish the following:

(a) For airplanes listed in McDonnell Douglas DC-9 Alert Service Bulletin A25-311, dated January 31, 1990: Within six months after August 14, 1990 (the effective date of AD 90-15-02, Amendment 39-6651), modify the forward cabin attendant dual seat, outboard position, lap belt restraint system, in accordance with the Accomplishment Instructions, Paragraph 2, of McDonnell Douglas DC-9 Alert Service Bulletin A25-311, dated January 31, 1990.

(b) For airplanes not listed in McDonnell Douglas DC-9 Alert Service Bulletin A25-311, dated January 31, 1990, and having dual forward cabin attendant seats incorporating a restraint system with lap belts independent of the shoulder harness: Within six months after the effective date of this AD, inspect the outboard attendant seat lap belt to determine if the connector or buckle is capable of reaching and interfering with the lower hinge of the passenger entrance door and obstructing the opening of the door.

(1) If opening of the passenger door entrance is obstructed, prior to further flight, modify the installation so that a shorter lap belt half is utilized, in a manner approved by the Manager, Los Angeles Aircraft Certification Office (ACO), FAA, Transport Airplane Directorate.

(2) If opening of the passenger entrance door is not obstructed, no further action is necessary.

(c) An alternate method of compliance or adjustment of the compliance time, which provides an acceptable level of safety, may be used when approved by the Manager, Los Angeles Aircraft Certification Office (ACO), FAA, Transport Airplane Directorate.

Note: This request should be forwarded through an FAA Principal Maintenance Inspector, who may concur or comment and then send it to the Manager, Los Angeles ACO.

Note: Any previously-approved alternative method of compliance with AD 90-15-02 is considered to be an approved alternative method of compliance with this AD.

Note: The procedures described in McDonnell Douglas DC-9 Alert Service Bulletin A25-321, dated August 8, 1991, are considered an approved alternative method of compliance with paragraph (b) of this AD.

(d) Special flight permits may be issued in accordance with FAR 21.197 and 21.199 to operate airplanes to a base in order to comply with the requirements of this AD.

(e) The modification requirements of paragraph (a) of this AD shall be done in accordance with McDonnell Douglas DC-9 Alert Service Bulletin A25-311, dated January 31, 1990. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from McDonnell Douglas Corporation, Post Office Box 1771, Long Beach, California 90801; Attn: Business Unit Manager, Technical Publications & Technical Administrative Support, C1-L5B (54-60). Copies may be inspected at the FAA, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington; or at the Los Angeles Aircraft Certification Office, 3229 East Spring Street, Long Beach, California; or at the Office of the Federal Register, 1100 L Street NW., room 8401, Washington, DC.

This amendment supersedes Amendment 39-6651, AD 90-15-02.

This amendment (39-8091, AD 91-24-05) becomes effective January 7, 1992.

Issued in Renton, Washington, on October 31, 1991.

Darrell M. Pederson,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 91-28945 Filed 12-2-91; 8:45 am]

BILLING CODE 4910-13-M

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14 CFR Part 39

[Docket No. 91-NM-223-AD; Amdt. 39-8095; AD 91-24-09]

Airworthiness Directives; McDonnell Douglas Model MD-11 and MD-11F Series Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to certain McDonnell Douglas Model MD-11 and MD-11F series airplanes, which requires inspections, repositioning, if necessary, and modification of the tail tank fuel pipe assembly in the aft fuselage compartment. This amendment is prompted by a report of an uncontained fuel leak in the aft fuselage compartment on an airplane in service. This condition, if not corrected, could result in a fuel leak in the aft fuselage compartment area, and the possibility of an in-flight or ground fire.

DATES: Effective December 18, 1991.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of December 18, 1991.

ADDRESSES: The applicable service information may be obtained from McDonnell Douglas Corporation, 3855 Lakewood Boulevard, Long Beach, California 90846, Attention: DC-10 Technical Publications, Technical Administrative Support, C1-L5B. This information may be examined at the FAA, Northwest Mountain Region, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington; or at the Los Angeles Aircraft Certification Office, 3229 East Spring Street, Long Beach, California; or at the Office of the Federal Register, 1100 L Street NW., room 8401, Washington, DC.

FOR FURTHER INFORMATION CONTACT: Mr. Raymond Vakili, Aerospace Engineer, Propulsion Branch, ANM-140L, FAA, Los Angeles Aircraft Certification Office, Transport Airplane Directorate, 3229 East Spring Street, Long Beach, California 90806-2425; telephone (213) 988-5262.

SUPPLEMENTARY INFORMATION: Recently, an uncontained fuel leak was detected in the aft fuselage compartment of a McDonnell Douglas Model MD-11 series airplane. Investigation has revealed that the tail tank fuel pipe assembly migrated, and subsequently exposed the O-ring that provides the seal between the pipe assembly and coupling shroud assembly. This resulted in fuel leaking into the aft fuselage compartment. Additionally, migration of the fuel pipe assembly caused an interference of the shroud assembly with an internal bonding clamp, resulting in a hole in the shroud. This condition, if not corrected, could result in a fuel leak in the aft fuselage compartment area, and the possibility of an in-flight or ground fire.

The FAA has reviewed and approved McDonnell Douglas MD-11 Alert Service Bulletin A28-22, Revision 4, dated September 16, 1991, which describes procedures for visually inspecting the tail tank fuel pipe assembly for the proper pipe flange position and the associated mounting brackets for damage, and, if necessary, for repositioning the fuel pipe assembly and replacing damaged mounting brackets. This service bulletin also describes procedures for installing additional fuel pipe assembly supporting clamps and brackets in the aft fuselage compartment.

The FAA has also reviewed and approved McDonnell Douglas Service Bulletin 28-22, dated September 24, 1991, which describes procedures for installing a new fuel pipe assembly and support bracket; installation of this fuel pipe assembly and support bracket precludes the need for the visual inspections.

Since this situation is likely to exist or develop on other airplanes of the same type design, this AD requires repetitive visual inspections and repositioning and replacement of the mounting brackets on the tail tank fuel pipe assembly in the aft fuselage compartment, if necessary, in accordance with Alert Service Bulletin A28-22, Revision 4, previously described. In addition, this AD provides for the installation of a new fuel pipe assembly and support bracket in accordance with Service Bulletin 28-22 as optional terminating action for the repetitive inspection requirements.

Since a situation exists that requires immediate adoption of this regulation, it is found that notice and public

procedure hereon are impracticable, and good cause exists for making this amendment effective in less than 30 days.

This is considered to be interim action. The FAA is considering further rulemaking to require the installation of the new fuel pipe assembly and support bracket, which is included in this rule as optional. However, the proposed compliance time is sufficiently long so that notice and public comment will not be impracticable.

The regulations adopted herein will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government. Therefore, in accordance with Executive Order 12612, it is determined that this final rule does not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

The FAA has determined that this regulation is an emergency regulation and that it is not considered to be major under Executive Order 12291. It is impracticable for the agency to follow the procedures of Order 12291 with respect to this rule since the rule must be issued immediately to correct an unsafe condition in aircraft. It has been determined further that this action involves an emergency regulation under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979). If it is determined that this emergency regulation otherwise would be significant under DOT Regulatory Policies and Procedures, a final regulatory evaluation will be prepared and placed in the Rule Docket. A copy of it, if filed, may be obtained from the Rules Docket.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

Adoption of the Amendment

Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration amends 14 CFR part 39 of the Federal Aviation Regulations as follows:

PART 39—[AMENDED]

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 1354(a), 1421 and 1423; 14 U.S.C. 106(g); and 14 CFR 11.89.

§39.13 [Amended]

2. Section 39.13 is amended by adding the following new airworthiness directive:

91-24-09. McDonnell Douglas: Amendment 39-8095. Docket No. 91-NM-223-AD.

Applicability: Model MD-11 and MD-11F series airplanes, with manufacturer's fuselage numbers 447, 448, 450 through 467, 469, 470, and 472, certificated in any category.

Compliance: Required as indicated, unless previously accomplished.

To prevent fuel leakage from the tail tank fuel pipe coupling shroud assembly when the shroud system contains fuel, accomplish the following:

(a) Within 50 flight hours after the effective date of this AD, visually inspect the tail tank fuel pipe assembly and the associated mounting brackets located in the aft fuselage compartment for correct pipe flange position and damaged brackets, in accordance with the accomplishment instructions of McDonnell Douglas MD-11 Alert Service Bulletin A28-22, Revision 4, dated September 16, 1991 (hereinafter referred to as SB A28-22-R4). Additionally, visually inspect the external surface of the shroud assembly, part number (P/N) 11175-103, for possible holes.

(1) If the position of the pipe flange is within the dimensions specified in SB A28-22-R4, and the mounting brackets are not cracked or deformed, repeat the inspections at intervals not to exceed 100 flight hours.

(2) If the pipe assembly pipe flange is positioned more than 0.250 inch (6.35 mm) from the aft end of the shroud assembly, or if mounting brackets are cracked or deformed, prior to further flight, accomplish either subparagraph (a)(2)(i) or (a)(2)(ii) of this AD.

(i) Reposition any pipe assembly that exceeds the dimensions specified in paragraph (a)(2) of this AD and replace damaged mounting brackets; and install a phenolic support block, two nylon clamps, and two brackets between the fuel pipes and fuselage station Y=2033.750 bulkhead; in accordance with the accomplishment instructions of SB A28-22-R4. After accomplishing these actions repeat the inspections required by paragraph (a) of this AD at intervals not to exceed 100 flight hours. Or

(ii) Replace the section of the tail tank fuel pipe assembly and support bracket in accordance with the accomplishment instructions of McDonnell Douglas Service Bulletin 28-22, dated September 24, 1991.

(3) If any hole is found on the P/N 11175-103 shroud assembly, prior to further flight, repair in accordance with an FAA-approved repair procedure, or replace the shroud assembly with a serviceable part.

(b) Replacement of a section of the fuel pipe assembly and support bracket in accordance with the accomplishment instructions of McDonnell Douglas Service Bulletin 28-22, dated September 24, 1991, constitutes terminating action for the inspection requirements of paragraph (a) of this AD.

(c) An alternative method of compliance or adjustment of the compliance time, which provides an acceptable level of safety, may be used when approved by the Manager, Los Angeles Aircraft Certification Office (ACO), FAA, Transport Airplane Directorate.

Note: The request should be forwarded through an FAA Principal Maintenance Inspector (PMI), who may concur or comment and then send it to the Manager, Los Angeles ACO.

(d) Special flight permits may be issued in accordance with FAR 21.197 and 21.199 to operate airplanes to a base in order to comply with the requirements of this AD.

(e) The inspection, repositioning, installation, and replacement requirements shall be done in accordance with McDonnell Douglas MD-11 Alert Service Bulletin A28-22, Revision 4, dated September 16, 1991; and McDonnell Douglas Service Bulletin 28-22, dated September 24, 1991. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from McDonnell Douglas Corporation, 3855 Lakewood Boulevard, Long Beach, California 90846, Attention: DC-10 Technical Publications, Technical Administrative Support, C1-5LB. Copies may be inspected at the FAA, Northwest Mountain Region, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington; or at the Los Angeles Aircraft Certification Office, 3229 East Spring Street, Long Beach, California; or at the Office of the Federal Register, 1100 L Street NW., room 8401, Washington, DC.

This amendment (39-8095, AD 91-24-09) becomes effective on December 18, 1991.

Issued in Renton, Washington, on November 4, 1991.

Darrell M. Pederson,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 91-28942 Filed 12-2-91; 8:45 am]

BILLING CODE 4910-13-M

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14 CFR Part 39

[Docket No. 91-NM-132-AD; Amdt. 39-8092; AD 91-24-06]

Airworthiness Directives; SAAB-Scania Models SF-340A and SAAB 340B Series Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to certain SAAB-Scania Models SF-340A and SAAB 340B series airplanes, which requires a one-time inspection and measurement of certain latches on the nacelle forward cowling doors to determine if the latch triggers are within certain specified limits, and the installation of new latch triggers, if necessary. This amendment is prompted by reports that the latch triggers on the nacelle forward cowling doors had been trimmed to make the latch fit the form of

the cowling surface, which could cause abnormal abrasion on the triggers and subsequent unlocking of the latches. This condition, if not corrected, could result in the cowling doors opening during flight.

DATES: Effective January 7, 1992.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of January 7, 1992.

ADDRESSES: The applicable service information may be obtained from SAAB-Scania AB, Product Support, S-581.88, Linköping, Sweden. This information may be examined at the FAA, Northwest Mountain Region, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington; or at the Office of the Federal Register, 1100 L Street NW., room 8401, Washington, DC.

FOR FURTHER INFORMATION CONTACT: Mr. Mark Quam, Standardization Branch, ANM-113; telephone (206) 227-2145. Mailing address: FAA, Northwest Mountain Region, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington 98055-4056.

SUPPLEMENTARY INFORMATION: A proposal to amend part 39 of the Federal Aviation Regulations to include a new airworthiness directive, applicable to certain SAAB-Scania Models SF-340A and SAAB 340B series airplanes, was published in the **Federal Register** on August 6, 1991 (56 FR 37320). That action proposed a one-time inspection and measurement of certain latches on the nacelle forward cowling doors to determine if the latch triggers are within certain specified limits, and the installation of new latch triggers, if necessary. The proposed requirements are intended to prevent the cowling doors from opening during flight.

Interested persons have been afforded an opportunity to participate in the making of this amendment. Due consideration has been given to the single comment received.

The commenter supported the rule.

After careful review of the available data, including the comment noted above, the FAA has determined that air safety and the public interest require the adoption of the rule as proposed.

It is estimated that 108 airplanes of U.S. registry will be affected by this AD, that it will take approximately 2 manhours per airplane to accomplish the required actions, and that the average labor cost will be $55 per manhour. Based on these figures, the total cost impact of the AD on U.S. operators is estimated to be $11,880.

The regulations adopted herein will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government. Therefore, in accordance with Executive Order 12612, it is determined that this final rule does not have sufficient federalism implications to warrant the preparations of a Federalism Assessment.

For the reasons discussed above, I certify that this action (1) is not a "major rule" under Executive Order 12291; (2) is not a "significant rule" under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979); and (3) will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act. A final evaluation has been prepared for this action and is contained in the Rules Docket. A copy of it may be obtained from the Rules Docket.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

The Proposed Amendment

Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration proposes to amend 14 CFR part 39 of the Federal Aviation Regulations as follows:

PART 39—[AMENDED]

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 1354(a), 1421 and 1423; 49 U.S.C. 106(g); and 14 CFR 11.89.

§ 39.13 [Amended]

2. Section 39.13 is amended by adding the following new airworthiness directive:

91-24-06. SAAB-Scania: Amendment 39-8092. Docket No. 91-NM-132-AD.

Applicability: Model SF-340A series airplanes, Serial Numbers 004 through 159; and Model SAAB 340B series airplanes, Serial Numbers 160 through 200; certificated in any category.

Compliance: Required as indicated, unless previously accomplished.

To prevent the cowling doors from opening during flight, accomplish the following:

(a) Within 90 days after the effective date of this AD, inspect and measure the Avibank latches on the nacelle forward cowling doors 7271110-501/601, in accordance with SAAB Service Bulletin 340-71-035, Revision 1, dated December 18, 1990.

(1) If the measurement is within the limits specified in Figure 2 of the service bulletin, no further action is required.

(2) If the measurement is outside the limits specified in Figure 2 of the service bulletin, prior to further flight, install new latch triggers in accordance with paragraph 2.C. of the service bulletin.

(b) An alternative method of compliance or adjustment of the compliance time, which provides an acceptable level of safety, may be used when approved by the Manager, Standardization Branch, ANM-113, FAA, Transport Airplane Directorate.

Note: The request should be forwarded through an FAA Principal Maintenance Inspector, who may concur or comment and then send it to the Manager, Standardization Branch, ANM-113.

(c) Special flight permits may be issued in accordance with FAR 21.197 and 21.199 to operate airplanes to a base in order to comply with the requirements of this AD.

(d) The inspection and replacement requirements shall be done in accordance with SAAB Service Bulletin 340-71-035, Revision 1, dated December 18, 1990. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from SAAB-Scania AB, Product Support, S-581.88, Linköping, Sweden. Copies may be inspected at the FAA, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, Washington; or at the Office of the Federal Register, 1100 L Street NW., room 8401, Washington, DC.

This amendment (39-8092, AD 91-24-06) becomes effective January 7, 1992.

Issued in Renton, Washington, on October 31, 1991.

Darrell M. Pederson,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 91-28951 Filed 12-2-91; 8:45 am]

BILLING CODE 4910-13-M

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14 CFR Part 71

[Airspace Docket No. 91-AGL-10]

Modification to Transition Area; Grayling Army Airfield, Grayling, MI

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: The nature of this action is to modify the existing Grayling Army Airfield, Grayling, MI transition area to accommodate a new VOR runway 14 Standard Instrument Approach Procedure (SIAP) to Grayling Army Airfield, Grayling, MI. The intended effect of this action is to ensure segregation of the aircraft using approach procedures in instrument conditions from other aircraft operating under visual weather conditions in controlled airspace.

EFFECTIVE DATE: 0901 UTC, March 5, 1992.

FOR FURTHER INFORMATION CONTACT: Douglas F. Powers, Air Traffic Division, System Management Branch, AGL–530, Federal Aviation Administration, 2300 East Devon Avenue, Des Plaines, Illinois 60018, telephone (312) 694–7568.

SUPPLEMENTARY INFORMATION:

History

On Thursday, September 26, 1991, the Federal Aviation Administration (FAA) proposed to amend part 71 of the Federal Aviation Regulations (14 CFR part 71) to modify a transition area airspace near Grayling, MI (56 FR 48769).

Interested parties were invited to participate in this rulemaking proceeding by submitting written comments on the proposal to the FAA. No comments objecting to the proposal were received.

Except for editorial changes, this amendment is the same as that proposed in the notice. Section 71.181 of part 71 of the Federal Aviation Regulations was republished in Handbook 7400.6G dated September 4, 1990.

The Rule

This amendment to part 71 of the Federal Aviation Regulations modifies the existing transition area airspace near Grayling, MI to accommodate a new VOR runway 14 SIAP to Grayling Army Airfield, Grayling, MI. This modification extends the existing Grayling, MI transition area 9.5 miles northeast of the Grayling VOR 298 radial from the 8 mile radius to 17.5 miles northwest of the airfield.

The development of a new SIAP requires that the FAA alter the designated airspace to insure that the procedure will be contained within controlled airspace. The minimum descent altitude for this procedure may be established below the floor of the 700-foot controlled airspace.

Aeronautical maps and charts will reflect the defined area which will enable other aircraft to circumnavigate the area in order to comply with applicable visual flight rule requirements.

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore—(1) is not a "major rule" under Executive Order 12291; (2) is not a "significant rule" under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 71

Aviation safety, Transition areas.

Adoption of the Amendment

Accordingly, pursuant to the authority delegated to me, part 71 of the Federal Aviation Regulations (14 CFR part 71) is amended, as follows:

PART 71—[AMENDED]

1. The authority citation for part 71 continues to read as follows:

Authority: 49 U.S.C. App. 1348(a), 1354(a), 1510; Executive Order 10854; 49 U.S.C. 106(g) (Revised Pub. L. 97–449, January 12, 1983); 14 CFR 11.69.

§ 71.181 [Amended]

2. Section 71.181 is amended as follows:

Grayling, MI [Revised]

That airspace extending upward from 700 feet above the surface within an 8 mile radius of the Grayling Army Airfield (lat. 440°40′49″N., long. 84°43′49″W.), Grayling, MI, and within 5 miles southwest and 9.5 miles northeast of the Grayling VOR (lat. 44°40′54″N., long. 84°43′44″W.) 298 radial extending from the Grayling VOR to 17.5 miles northwest of the airfield.

Issued in Des Plaines, Illinois on November 15, 1991.

Teddy W. Burcham,

Manager, Air Traffic Division.

[FR Doc. 91–28981 Filed 12–2–91; 8:45 am]

BILLING CODE 4910–13–M

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14 CFR Part 71

[Airspace Docket No. 91–AGL–8]

Transition Area Alteration; Willmar, MN

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: The nature of this action is to modify the existing Willmar, Minnesota transition area to accommodate revised VOR Runways 10 and 28 Standard Instrument Approach Procedures (SIAPs) to Willmar Municipal Airport–John L. Rice Field. The intended effect of this action is to ensure segregation of the aircraft using approach procedures in instrument conditions from other aircraft operating under visual weather conditions in controlled airspace.

EFFECTIVE DATE: 0901 UTC, March 5, 1992.

FOR FURTHER INFORMATION CONTACT: Douglas F. Powers, Air Traffic Division, System Management Branch, AGL–530, Federal Aviation Administration, 2300 East Devon Avenue, Des Plaines, Illinois 60018, telephone (312) 694–7568.

SUPPLEMENTARY INFORMATION:

History

On Thursday, August 22, 1991, the Federal Aviation Administration (FAA) proposed to amend part 71 of the Federal Aviation Regulations (14 CFR part 71) to modify the transition area airspace near Willmar Municipal Airport, Willmar, Minnesota. (56 FR 41633).

Interested parties were invited to participate in this rulemaking proceeding by submitting written comments on the proposal to the FAA. No comments objecting to the proposal were received.

Except for editorial changes, this amendment is the same as that proposed in the notice. Section 71.181 of part 71 of the Federal Aviation Regulations was republished in Handbook 7400.6G dated September 4, 1990.

The Rule

This amendment to part 71 of the Federal Aviation Regulations alters the designated airspace near Willmar, MN. The transition area is being altered to accommodate revised VOR Runways 10 and 28 SIAPs to Willmar Municipal Airport–John L. Rice Field.

The revised SIAPs require that the FAA alter the designated airspace to insure that the procedures will be contained within controlled airspace. The minimum descent altitude for the procedures may be established below the floor of the 700-foot controlled airspace.

Aeronautical maps and charts will reflect the defined area which will enable other aircraft to circumnavigate the area in order to comply with applicable visual flight rule requirements.

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore—(1) is not a "major rule" under Executive Order 12291; (2) is not a "significant rule" under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3)

does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 71

Aviation safety, Transition areas.

Adoption of the Amendment

Accordingly, pursuant to the authority delegated to me, part 71 of the Federal Aviation Regulations (14 CFR part 71) is amended, as follows:

PART 71 [AMENDED]

1. The authority citation for part 71 continues to read as follows:

Authority: 49 U.S.C. App. 1348(a), 1354(a), 1510; Executive Order 10854; 49 U.S.C. 106(g) (Revised Pub. L. 97–449, January 12, 1983); 14 CFR 11.69.

§ 71.181 [Amended]

2. Section 71.181 is amended as follows:

Willmar, MN [Revised]

That airspace extending upward from 700 feet above the surface within a 8-mile radius of the Willmar Municipal Airport–John L. Rice Field (lat. 45°07′00″N., long. 95°05′24″W.).

Issued in Des Plaines, Illinois on November 9, 1991.

Teddy W. Burcham,

Manager, Air Traffic Division.

[FR Doc. 91–28917 Filed 12–2–91; 8:45 am]

BILLING CODE 4910–13–M

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14 CFR Part 97

[Docket No. 26685; Amdt. No. 1465]

Standard Instrument Approach Procedures: Miscellaneous Amendments

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This amendment establishes, amends, suspends, or revokes Standard Instrument Approach Procedures (SIAPs) for operations at certain airports. These regulatory actions are needed because of changes occurring in the National Airspace System, such as the commissioning of new navigational facilities, addition of new obstacles, or changes in air traffic requirements. These changes are designed to provide safe and efficient use of the navigable airspace and to promote safe flight operations under instrument flight rules at the affected airports.

DATES: *Effective:* An effective date for each SIAP is specified in the amendatory provisions.

Incorporation by reference-approved by the Director of the Federal Register on December 31, 1980, and reapproved as of January 1, 1982.

ADDRESSES: Availability of matter incorporated by reference in the amendment is as follows:

For Examination—

1. FAA Rules Docket, FAA Headquarters Building, 800 Independence Avenue, SW., Washington, DC 20591;
2. The FAA Regional Office of the region in which affected airport is located; or
3. The Flight Inspection Field Office which originated the SIAP.

For Purchase—

Individual SIAP copies may be obtained from:

1. FAA Public Inquiry Center (APA–200), FAA Headquarters Building, 800 Independence Avenue, SW., Washington, DC 20591; or
2. The FAA Regional Office of the region in which the affected airport is located.

By Subscription—

Copies of all SIAPs, mailed once every 2 weeks, are for sale by the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402.

FOR FURTHER INFORMATION CONTACT: Paul J. Best, Flight Procedures Standards Branch (AFS–420), Technical Programs Division, Flight Standards Service, Federal Aviation Administration, 800 Independence Avenue, SW., Washington, DC 20591; telephone (202) 267–8277.

SUPPLEMENTARY INFORMATION: This amendment to part 97 of the Federal Aviation Regulations (14 CFR part 97) establishes, amends, suspends, or revokes Standard Instrument Approach Procedures (SIAPs). The complete regulatory description on each SIAP is contained in the appropriate FAA Form 8260 and the National Flight Data Center (FDC)/Permanent (P) Notices to Airmen (NOTAM) which are incorporated by reference in the amendment under 5 U.S.C. 552(a), 1 CFR part 51, and § 97.20 of the Federal Aviations Regulations (FAR). Materials incorporated by reference are available for examination or purchase as stated above.

The large number of SIAPs, their complex nature, and the need for a special format make their verbatim publication in the **Federal Register** expensive and impractical. Further, airmen do not use the regulatory text of the SIAPs, but refer to their graphic depiction of charts printed by publishers of aeronautical materials. Thus, the advantages of incorporation by reference are realized and publication of the complete description of each SIAP contained in FAA form documents is unnecessary. The Provisions of this amendment state the affected CFR (and FAR) sections, with the types and effective dates of the SIAPs. This amendment also identifies the airport, its location, the procedure identification and the amendment number.

The Rule

This amendment to part 97 of the Federal Aviation Regulations (14 CFR part 97) establishes, amends, suspends, or revokes SIAPs. For safety and timeliness of change considerations, this amendment incorporates only specific changes contained in the content of the following FDC/P NOTAM for each SIAP. The SIAP information in some previously designated FDC/Temporary (FDC/T) NOTAMs is of such duration as to be permanent. With conversion to FDC/P NOTAMs, the respective FDC/T NOTAMs have been canceled. The FDC/P NOTAMs for the SIAPs contained in this amendment are based on the criteria contained in the U.S. Standard for Terminal Instrument Approach Procedures (TERPs). In developing these chart changes to SIAPs by FDC/P NOTAMs, the TERPs criteria were applied to only these specific conditions existing at the affected airports.

This amendment to part 97 is effective upon publication of each separate SIAP as contained in the transmittal. All SIAP amendments in this rule have been previously issued by the FAA in a National Flight Center (FDC) Notice Airmen (NOTAM) as an emergency action of immediate flight safety relating directly to published aeronautical charts. The circumstances which created the need for all these SIAP amendments requires making them effective in less than 30 days.

Further, the SIAPs contained in this amendment are based on the criteria contained in the U.S. Standard for Terminal Instrument Approach Procedures (TERPs). Because of the close and immediate relationship between these SIAPs and safety in air commerce, I find that notice and public procedure before adopting these SIAPs

are unnecessary, impracticable, and contrary to the public interest and, where applicable, that good cause exists for making these SIAPs effective in less than 30 days.

Conclusion

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore—(1) is not a "major rule" under Executive Order 12291; (2) is not a "significant rule" under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. For the same reason, the FAA certifies that this amendment will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 97

Air traffic control, Airports, Incorporation by reference, Navigation (Air), Standard instrument approaches, Weather.

Issued in Washington, DC on November 8, 1991.

Thomas C. Accardi,

Director, Flight Standards Service.

Adoption of the Amendment

Accordingly, pursuant to the authority delegated to me, part 97 of the Federal Aviation Regulations (14 CFR part 97) is amended by establishing, amending, suspending, or revoking Standard Instrument Approach Procedures, effective at 0901 UTC on the dates specified, as follows:

PART 97—STANDARD INSTRUMENT APPROACH PROCEDURES

1. The authority citation for part 97 continues to read as follows:

Authority: 49 U.S.C. App. 1348, 1354(a), 1421 and 1510; 49 U.S.C. 106(g) (revised Pub. L. 97–449, January 12, 1983); and 14 CFR 11.49(b)(2).

2. Part 97 is amended to read as follows:

By amending: § 97.23 VOR, VOR/DME, VOR or TACAN, and VOR/DME or TACAN; § 97.25 LOC, LOC/DME, LDA, LDA/DME, SDF, SDF/DME; § 97.27 NDB, NDB/DME; § 97.29 ILS, ILS/DME, ISMLS, MLS, MLS/DME, MLS/RNAV; § 97.31 RADAR SIAPs; § 97.33 RNAV SIAPs; and § 97.35 COPTER SIAPs, identified as follows:

NFDC TRANSMITTAL LETTER

Effective	State	City	Airport	FDC No.	SIAP
01/11/91	PA	Johnstown	Johnstown-Cambria County	FDC 1/4755	VOR RWY 23 AMDT 6.
01/11/91	TX	Conroe	Montgomery County	FDC 1/5386	LOC RWY 14, ORIG.
09/26/91	CA	Redding	Redding Muni	FDC 1/4660	VOR RWY 34 AMDT 10.
10/08/91	TN	Knoxville	McGhee Tyson	FDC 1/4934	ILS RWY 23R AMDT 10 CAT II.
10/09/91	MI	Sault Ste Marie	Chippewa County Intl	FDC 1/4941	ILS RWY 16 AMDT 7.
10/09/91	MI	Sault Ste Marie	Chippewa County Intl	FDC 1/4942	VOR-A OR TACAN-A AMDT 5.
10/09/91	MI	Sault Ste Marie	Chippewa County Intl	FDC 1/4943	NDB RWY 34 AMDT 4.
10/09/91	MI	Sault Ste Marie	Chippewa County Intl	FDC 1/4944	NDB RWY 16 AMDT 5.
10/25/91	AK	Yakutat	Yakutat	FDC 1/5281	ILS RWY 11 AMDT 3.
10/30/91	OH	Cleveland	Cleveland/Cuyahoga County	FDC 1/5360	ILS RWY 23 AMDT 10.
10/30/91	TX	Kountze/Silsbee	Hawthorne Field	FDC 1/5358	NDB RWY 13 ORIG.
10/31/91	PA	Altonna	Altonna-Blair County	FDC 1/5363	VOR-A AMDT 3.
10/31/91	PA	Altonna	Altonna-Blair County	FDC 1/5364	ILS RWY 20 AMDT 4.
11/01/91	TN	Gallatin	Sumner County Regional	FDC 1/5416	NDB RWY 35 ORIG.

NFDC Transmittal Letter Attachment

Yakutat

YAKUTAT
Alaska
Ils RWY 11 AMDT 3...
Effective: 10/25/91

FDC 1/5281/YAK/ FI/P YAKUTAT, YAKUTAT, AK ILS RWY 11 AMDT 3 . . . S-LOC AND CIRCLING MISSED APCH POINT 3.5 NM AFT FAF OR .6 DME. ADF REQUIRED. REMOVE LIGHT NOTE . . . WHEN YAK FSS CLOSED, ACTIVATE MALSR RWY 11 AND HIRL RWY 11–29 123.6. REMOVE NOTE . . . IF OM INOP, SIMULTANOUS RECEPTION OF I-YAK ILS AND YAK DME REQUIRED. DME IS ILS FROM YAK VORTAC. THIS IS RWY 11 AMDT 3A.

Redding

REDDING MUNI
California
VOR RWY 34 AMDT 10 . . .
Effective: 09/26/91

FDC 1/4660/RDD/ FI/P REDDING MUNI, REDDING, CA. VOR RWY 34 AMDT 10 . . . S-34 MDA 1260/HAT 764 ALL CATS. VIS CAT A 1/2, CAT B 3/4, CAT C 1-3/4, CAT D 2. CIRCLING MDA 1260/HAA 758 ALL CATS. VIS CAT A 1. CAT B 1-1/4, CAT C 800 2-1/4, CAT D 800 2-1/2. THIS BECOMES VOR RWY 34 AMDT 10A.

Sault Ste Marie

CHIPPEWA COUNTY INTL
Michigan
ILS RWY 16 AMDT 7 . . .
Effective: 10/09/91

FDC 1/4941/CIU/ FI/P CHIPPEWA COUNTY INTL, SAULT STE MARIE, MI. ILS RWY 16 AMDT 7 . . . CHANGE ALSTG NOTE TO READ, "IF LOCAL ASTG NOT RECEIVED USE SAULT STE MARIE CANADA ALSTG AND INCREASE ALL SH/MDA'S 60 FT." THIS IS ILS RWY 16 AMDT 7A.

Sault Ste Marie

CHIPPEWA COUNTY INTL
Michigan
VOR-A OR TACAN-A AMDT 5 . . .
Effective: 10/09/91

FDC 1/4942/CIU/ FI/P CHIPPEWA COUNTY INTL, SAULT STE MARIE, MI. VORA OR TACAN-A AMDT 5 . . . CHANGE ALSTG NOTE TO READ, "IF LOCAL ALSTG NOT RECEIVED USE SAULT STE MARIE CANADA ALSTG AND INCREASE ALL MDA'S 60 FT." CHANGE ALTERNATE MINIMUMS TO STANDARD. THIS IS VOR-A OR TACAN-A AMDT 5A.

Sault Ste Marie

CHIPPEWA COUNTY INTL
Michigan
NDB RWY 34 AMDT 4 . . .
Effective: 10/09/91

FDC 1/4943/CIU/ FI/P CHIPPEWA COUNTY INTL, SAULT STE MARIE, MI NDB RWY 34 AMDT 4 . . . CHANGE ALSTG NOTE TO READ, "IF LOCAL ALSTG NOT RECEIVED USE SAULT STE CANADA ALSTG AND INCREASE ALL MDA'S 60 FT." THIS IS NDB RWY 34 AMDT 4A.

Sault Ste Marie

CHIPPEWA COUNTY INTL
Michigan
NDB RWY 16 AMDT 5 . . .
Effective: 10/09/91

FDC 1/4944/CIU/ FI/P CHIPPEWA COUNTY INTL, SAULT STE MARIE, MI NDB RWY 16 AMDT 5 . . . CHANGE ALSTG NOTE TO READ, "IF LOCAL ALSTG NOT RECEIVED USE SAULT STE MARIE CANADA ALSTG AND INCREASE ALL MDA'S 60 FT." THIS IS NDB RWY 16 AMDT 5A.

Cleveland

CLEVELAND/CUYAHOGA COUNTY
Ohio
ILS RWY 23 AMDT 10 . . .
Effective: 01/30/91

FDC 1/5360/CGF/ FI/P CLEVELAND/ CUYAHOGA COUNTY, CLEVELAND, OH ILS RWY 23 AMDT 10 . . . DELETE NOTE . . . WHEN USING CUYAHOGA COUNTY ALTIMETER CAT D S-LOC 23 VISIBILITY INCREASED 1/4 MILE FOR INOPERATIVE MIDDLE MARKER. THIS IS ILS RWY 23 AMDT 10A.

Johnstown

JOHNSTOWN-CAMBRIA COUNTY
Pennsylvania
VOR RWY 23 AMDT 6 . . .
Effective: 01/11/91

FDC 1/4755/JST/ FI/P JOHNSTOWN-CAMBRIA COUNTY, JOHNSTOWN, PA. VOR RWY 23 AMDT 6 . . . ENTIRE NOTE PERTAINING TO WHEN CONTROL ZONE NOT IN EFFECT DELETED. DELETE PROFILE NOTE . . . - 3800 WHEN CONTROL ZONE NOT IN EFFECT. ALTERNATE MIN . . . STANDARD. THIS BECOMES VOR RWY 23 AMDT 6A.

Altonna

ALTONNA-BLAIR COUNTY
Pennsylvania
VOR-A AMDT 3...
Effective: 10/31/91

FDC 1/5363/AOO/ FI/P ALTONNA-BLAIR COUNTY, ALTONNA, PA. VOR-A AMDT 3...DELETE "NOTES"... PRECIPITOUS TERRAIN....THRU....RWY 20 CTAF. DELETE TERMINAL ROUTE OBURY INT TO AOO VOR COURSE/ DISTANCE/ALT (033/1.8 4200). THIS BECOMES VOR-A AMDT 3A.

Altoona

ALTOONA-BLAIR COUNTY
Pennsylvania
ILS RWY 20 AMDT 4...
Effective: 10/31/91

FDC 1/5364/AOO/ FI/P ALTOONA-BLAIR COUNTY, ALTOONA, PA. ILS RWY 20 AMDT 4...S-ILS-20 DH 1737, HAT 250, VIS 3/4 ALL CATS. S-LOC-20 VIS CAT A 3/4. ADD NOTE... INOP TABLE APPLIES ONLY TO S-LOC-20 CATS A AND B. DELETE "NOTES" PRECIPITIOUS TERRAIN.....THRU....RWY 20-CTAF. DELETE TERMINAL ROUTE OBURY INT TO AOO VOR COURSE/ DISTANCE/ALT (033/1.8 4200). THIS BECOMES ILS RWY 20 AMDT 4A.

Knoxville

MCGHEE TYSON
Tennessee
ILS RWY 23 R AMDT 10 CAT II...
Effective: 10/08/91

FDC 1/4934/TYS/ FI/P MCGHEE TYSON, KNOXVILLE, TN. ILS RWY 23R AMDT 10 CAT II...CAT II ILS SPECIAL AIRCREW AND AIRCRAFT CERTIFICATION REQUIRED. S-ILS 23R DH 1140 MSL, 187 RA, RVR 1600, HAT 159 CAT A,B,C,D. S-ILS 23R DH 1090 MSL, 115 RA, RVR 1200, HAT 109 CAT A,B,C,D. THIS IS ILS RWY 23R AMDT 10A.

Gallatin

SUMNER COUNTY REGIONAL
Tennessee
NDB RWY 35 ORIG...
Effective: 11/01/91

FDC 1/5416/M33/ FI/P SUMNER COUNTY REGIONAL, GALLATIN, TN. NDB RWY 35 ORIG...TRML ROUTE... CASHO INT TO GYN NDB ALT 3000. TRML ROUTE...LENON INT TO GYN NDB ALT 2200. TRML ROUTE...BNA VORTAC TO GYN NDB ALT 2200. THIS IS NDB RWY 35 ORIG A.

Kountze/Silsbee

HAWTHORNE FIELD
Texas
NDB RWY 13 ORIG...
Effective: 10/30/91

FDC 1/5358/45R/ FI/P HAWTHORNE FIELD, KOUNTZE/SILSBEE, TX. NDB RWY 13 ORIG...MSA FROM HRD NDB 170-260 3100, 260-170 2300. THIS BECOMES NDB RWY 13 ORIG A.

Conroe

MONTGOMERY COUNTY
Texas
LOC RWY 14, ORIG...
Effective: 01/11/91

FDC 1/5386/CXO/ FI/P MONTGOMERY COUNTY, CONROE, TX. LOC RWY 14, ORIG...TERMINAL ROUTE... DAS VORTAC TO ALIBI LOM 2300. THIS BECOMES LOC RWY 14, ORIG A.

[FR Doc. 91-28919 Filed 12-2-91;8:45 am]

BILLING CODE 4910-13-M

14 CFR Part 97

[Docket No. 26694; Amdt. No. 1466]

Standard Instrument Approach Procedures; Miscellaneous Amendments

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This amendment establishes, amends, suspends, or revokes Standard Instrument Approach Procedures (SIAPs) for operations at certain airports. These regulatory actions are needed because of the adoption of new or revised criteria, or because of changes occurring in the National Airspace System, such as the commissioning of new navigational facilities, addition of new obstacles, or changes in air traffic requirements. These changes are designed to provide safe and efficient use of the navigable airspace and to promote safe flight operations under instrument flight rules at the affected airports.

DATES: *Effective:* An effective date for each SIAP is specified in the amendatory provisions.

Incorporation by reference—approved by the Director of the Federal Register on December 31, 1980, and reapproved as of January 1, 1982.

ADDRESSES: Availability of matters incorporated by reference in the amendment is as follows:

For Examination

1. FAA Rules Docket, FAA Headquarters Building, 800 Independence Avenue, SW., Washington, DC 20591;
2. The FAA Regional Office of the region in which the affected airport is located; or
3. The Flight Inspection Field Office which originated the SIAP.

For Purchase

Individual SIAP copies may be obtained from:

1. FAA Public Inquiry Center (APA-200), FAA Headquarters Building, 800 Independence Avenue, SW., Washington, DC 20591; or
2. The FAA Regional Office of the region in which the affected airport is located.

By Subscription

Copies of all SIAPs, mailed once every 2 weeks, are for sale by the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402.

FOR FURTHER INFORMATION CONTACT: Paul J. Best, Flight Procedures Standards Branch (AFS-420), Technical Programs Division, Flight Standards Service, Federal Aviation Administration, 800 Independence Avenue, SW., Washington, DC 20591; telephone (202) 267-8277.

SUPPLEMENTARY INFORMATION: This amendment to part 97 of the Federal Aviation Regulations (14 CFR part 97) establishes, amends, suspends, or revokes Standard Instrument Approach Procedures (SIAPs). The complete regulatory description of each SIAP is contained in official FAA form documents which are incorporated by reference in this amendment under 5 U.S.C. 552(a), 1 CFR part 51, and § 97.20 of the Federal Aviation Regulations (FAR). The applicable FAA Forms are identified as FAA Forms 8260-3, 8260-4, and 8260-5. Materials incorporated by reference are available for examination or purchase as stated above.

The large number of SIAPs, their complex nature, and the need for a special format make their verbatim publication in the **Federal Register** expensive and impractical. Further, airmen do not use the regulatory text of the SIAPs, but refer to their graphic depiction on charts printed by publishers of aeronautical materials. Thus, the advantages of incorporation by reference are realized and publication of the complete description of each SIAP contained in FAA form documents is unnecessary. The provisions of this amendment state the affected CFR (and FAR) sections, with the types and effective dates of the SIAPs. This amendment also identifies the airport, its location, the procedure identification and the amendment number.

This amendment to part 97 is effective upon publication of each separate SIAP as contained in the transmittal. Some SIAP amendments may have been previously issued by the FAA in a National Flight Data Center (FDC) Notice to Airmen (NOTAM) as an emergency action of immediate flight safety relating directly to published aeronautical charts. The circumstances which created the need for some SIAP amendments may require making them effective in less than 30 days. For the remaining SIAPs, an effective date at least 30 days after publication is provided.

Further, the SIAPs contained in this amendment are based on the criteria contained in the U.S. Standard for Terminal Instrument Approach Procedures (TERPs). In developing these SIAPs, the TERPS criteria were applied to the conditions existing or anticipated at the affected airports. Because of the close and immediate relationship between these SIAPs and safety in air commerce, I find that notice and public procedure before adopting these SIAPs are unnecessary, impractical, and contrary to the public interest and, where applicable, that good cause exists for making some SIAPs effective in less that 30 days.

The FAA has determined that this regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore—(1) is not a "major rule" under Executive Order 12291; (2) is not a "significant rule" under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a regulatory evaluation as the anticipated impact is so minimal. For the same reason, the FAA certifies that this amendment will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 97

Air traffic control, Airports, Incorporation by reference, Navigation (Air), Standard instrument approaches, Weather.

Issued in Washington, DC on November 8, 1991.

Thomas C. Accardi,

Director, Flight Standards Service.

Adoption of the Amendment

Accordingly, pursuant to the authority delegated to me, part 97 of the Federal Aviation Regulations (14 CFR part 97) is amended by establishing, amending, suspending, or revoking Standard Instrument Approach Procedures, effective at 0901 UTC on the dates specified, as follows:

PART 97—STANDARD INSTRUMENT APPROACH PROCEDURES

1. The authority citation for part 97 continues to read as follows:

Authority: 49 U.S.C. App. 1348, 1354(a), 1421 and 1510; 49 U.S.C. 106(g) (Revised Pub. L. 97-449, January 12, 1983); and 14 CFR 11.49 (b)(2).

2. Part 97 is amended to read as follows:

By amending: § 97.23 VOR, VOR/DME, VOR or TACAN, and VOR/DME or TACAN; § 97.25 LOC, LOC/DME, LDA, LDA/DME, SDF, SDF/DME; § 97.27 NDB, NDB/DME; § 97.29 ILS, ILS/DME, ISMLS, MLS, MLS/DME, MLS/RNAV; § 97.31 RADAR SIAPs; § 97.33 RNAV SIAPs; and § 97.35 COPTER SIAPs, identified as follows:

* * * **Effective January 9, 1992**

Rogers, AR—Rogers Municipal-Carter Field, LOC RWY 19, Orig., CANCELLED
Grass Valley, CA—Nevada County Air Park, VOR RWY 7, Orig., CANCELLED
Grass Valley, CA—Nevada County Air Park, VOR-A, Orig.
Danville, KY—Goodall Field, NDB-A, Amdt. 5
Hawesville, KY—Hancock Airfield, VOR RWY 15, Amdt. 5
Hawesville, KY—Hancock Airfield, VOR RWY 33, Amdt. 5
Hawesville, KY—Hancock Airfield, NDB-A, Amdt. 5
Morganton, NC—Morganton-Lenoir, SDF RWY 3, Amdt. 5, CANCELLED
Morganton, NC—Morganton-Lenoir, LOC RWY 3, Orig.
Oxford, NC—Henderson-Oxford, LOC RWY 6, Orig.
Newport, OR—Newport Muni, VOR-A, Amdt. 3
Newport, OR—Newport Muni, VOR/DME RWY 16, Amdt. 7
Johnson-Kingsport, TN—Tri-City Regional, NDB RWY 5, Amdt. 16
Bristol-Johnson-Kingsport, TN—Tri-City Regional, NDB RWY 23, Amdt. 18
Bristol-Johnson-Kingsport, TN—Tri-City Regional, ILS RWY 5, Amdt. 1
Bristol-Johnson-Kingsport, TN—Tri-City Regional, ILS RWY 23, Amdt. 23
Bristol-Johnson-Kingsport, TN—Tri-City Regional, RADAR-1, Amdt.15
Trenton, TN—Gibson County, VOR/DME-A, Amdt. 5
Trenton, TN—Gibson County, NDB RWY 19, Amdt. 3

* * * **Effective December 12, 1991**

Casa Grande, AZ—Casa Grande Muni, ILS/DME RWY 5, Amdt. 5
Oroville, CA—Oroville Muni, NDB RWY 1, Amdt. 1
Vero Beach, FL—Vero Beach Muni, NDB RWY 11R, Amdt. 1
Baltimore, MD—Baltimore-Washington Intl, ILS/DME RWY 15L, Amdt. 1
Baltimore, MD—Baltimore-Washington Intl, ILS RWY 15R, Amdt. 12
Baltimore, MD—Baltimore-Washington Intl, ILS/DME RWY 33R, Amdt. 1
Cambridge, MD—Cambridge-Dorchester, VOR-A, Amdt. 4, CANCELLED
College Park, MD—College Park, VOR/DME RNAV RWY 15, Amdt. 1
Bedford, MA—Laurence G. Hanscom Fld, ILS RWY 29, Amdt. 3
Nashua, NH—Boire Field, VOR/DME RWY 32, Orig.
Buffalo, NY—Greater Buffalo Intl, RADAR-1, Amdt. 13, CANCELLED
Akron, OH—Akron-Canton Regional, VOR RWY 5, Amdt. 1
Akron, OH—Akron-Canton Regional, VOR RWY 23, Amdt. 8
Akron, OH—Akron-Canton Regional, ILS RWY 1, Amdt. 35
Akron, OH—Akron-Canton Regional, ILS RWY 19, Amdt. 5

Akron, OH—Akron-Canton Regional, ILS RWY 23, Amdt. 9
Akron, OH—Akron-Canton Regional, RADAR-1, Amdt. 20
Dayton, OH—Greene County, VOR-A, Amdt. 1
Hillsboro, OH—Highland County, VOR/DME-A, Amdt. 1
Lorain/Elyria, OH—Lorain County Regional, VOR RWY 7, Amdt. 12, CANCELLED
Wooster, OH—Wayne County, NDB RWY 27, Amdt. 6
Lancaster, PA—Lancaster, VOR/DME RWY 26, Amdt. 7
Somerset, PA—Somerset County, LOC RWY 24, Amdt. 2
Somerset, PA—Somerset County, NDB RWY 24, Amdt. 4
Longview, TX—Gregg County, VOR or TACAN RWY 13, Amdt. 19
Longview, TX—Gregg County, VOR/DME or TACAN RWY 31, Amdt. 6
Longview, TX—Gregg County, NDB RWY 13 Amdt. 13
Longview, TX—Gregg County, ILS RWY 13 Amdt. 9
Longview, TX—Gregg County, RADAR-1, Amdt. 3
Longview, TX—Gregg County, VOR/DME RNAV RWY 22, Amdt. 6
Waco, TX—Waco Regional, VOR RWY 14, Amdt. 20
Waco, TX—Waco Regional, VOR/DME RWY 32, Amdt. 13
Waco, TX—Waco Regional, LOC BC RWY 1, Amdt. 9
Waco, TX—Waco Regional, NDB RWY 19, Amdt. 16
Waco, TX—Waco Regional, ILS RWY 19, Amdt. 13
Waco, TX—Waco Regional, RADAR-1, Amdt. 2

[FR Doc. 91-28918 Filed 12-2-91; 8:45 am]

BILLING CODE 4910-13-M

DEPARTMENT OF JUSTICE

Drug Enforcement Administration

21 CFR Part 1308

Schedules of Controlled Substances; Removal of Propylhexedrine From Control

AGENCY: Drug Enforcement Administration (DEA), Justice.

ACTION: Notice of final rulemaking.

SUMMARY: This final rule is issued by the Administrator of the DEA in order to remove propylhexedrine from the Schedules of the Controlled Substances Act (CSA). As a result of this rule, propylhexedrine and products containing propylhexedrine will no longer be subject to the provisions of the CSA. Propylhexedrine was placed in Schedule V of the CSA in April 1988 in conformity with international control of the drug under the 1971 Convention on Psychotropic Substances. On June 10, 1991, the United States was notified that propylhexedrene had been decontrolled internationally, thus, obviating the need for domestic control under the CSA.

EFFECTIVE DATE: This action is effective December 3, 1991.

FOR FURTHER INFORMATION CONTACT: Howard McClain, Jr., Chief, Drug and Chemical Evaluation Section, Office of Diversion Control, Drug Enforcement Administration, Washington, DC 20537, telephone: (202) 307-7183.

SUPPLEMENTARY INFORMATION: On February 11, 1986, the United Nations Commission on Narcotic Drugs (UNCND) decided that propylhexedrine should be included in Schedule IV of the 1971 Convention on Psychotropic Substances. The Secretary of State was formally notified of this decision by the Secretary-General of the United Nations on February 28, 1986. Subsequently, the United States Government, believing that there was insufficient evidence to support scheduling of propylhexedrine under either the Convention or the CSA, requested that the UNCND reconsider its scheduling decision. The United States also requested that the World Health Organization (WHO) undertake a complete review of the UNCND's previous decision on the scheduling of propylhexedrine.

Section 201(d) of the CSA (21 U.S.C. 811(d)) makes provisions for temporary domestic control of substances when the United States formally request reconsideration of the international control. The purpose of these provisions is to insure that the United States, by establishing minimum controls, will remain in compliance with its obligations under the pertinent treaties and conventions. Accordingly, on April 4, 1988, the Administrator of the DEA, citing the United States efforts to obtain review of the UNCND scheduling action, published a final rule, placing propylhexedrine in Schedule V of the CSA. The final rule was published in the **Federal Register**, volume 53, at page 10869.

In September 1990, the 27th WHO Expert Committee on Drug Dependence examined the international scheduling of propylhexedrine. Based on new data, the Expert Committee recommended to WHO that propylhexedrine be removed from international control. WHO notified the Secretary-General of its recommendation and on April 29, 1991, the matter was presented to the UNCND which concurred with the WHO recommendation. The United States was formally notified of the deletion of propylhexedrine from international control on June 10, 1991.

Accordingly, pursuant to the provisions of 21 U.S.C. 811(d)(4)(B), the Administrator of the DEA hereby orders that propylhexedrine be, and it hereby is, decontrolled.

In accordance with the provisions of 21 U.S.C. 811(a), this action is a formal rulemaking "on the record after the opportunity for a hearing". Such proceedings are conducted pursuant to the provisions of 5 U.S.C. 556 and 557 and, as such, have been exempted from the consultation requirements of Executive Order 12291 (46 FR 13193).

Pursuant to 5 U.S.C. 605(b), the Administrator certifies that the decontrol of propylhexedrine will have no significant economic impact upon entities whose interests must be considered under the Regulatory Flexibility Act (Pub. L. 96-354). Decontrol of a substance relieves manufacturers and other registrants of the regulatory requirements relating to controlled substances.

This action has been analyzed in accordance with the principles and criteria contained in Executive Order 12612, and it has been determined that this matter does not have sufficient federalism implications to warrant preparation of a Federalism Assessment.

List of Subjects in 21 CFR Part 1308

Administrative practice and procedure, Drug traffic control, Narcotics and prescription drugs.

Under the authority vested in the Attorney General by section 201(a) of the CSA (21 U.S.C. 811(a)) and delegated to the Administrator of the DEA by Department of Justice Regulations (28 CFR 0.100), the Administrator hereby proposes that title 21 CFR, part 1308 be amended as follows:

PART 1308—[AMENDED]

1. The authority citation for title 21, CFR part 1308 continues to read as follows:

Authority: 21 U.S.C. 811, 812, 871(b), unless otherwise noted.

§ 1308.15 [Amended]

2. Section 1308.15 is amended by removing paragraph (d)(1) and redesignating paragraph (d)(2) as (d)(1).

Dated: November 20, 1991.

Robert C. Bonner,

Administrator of Drug Enforcement.

[FR Doc. 91-28868 Filed 12-2-91; 8:45 am]

BILLING CODE 4410-09-M

NATIONAL LABOR RELATIONS BOARD

29 CFR Part 102

Procedural Rules; Correction

AGENCY: National Labor Relations Board.

ACTION: Final rules; correction.

SUMMARY: On September 27, 1991, the National Labor Relations Board published at 56 FR 49141 revisions to its rules which, *inter alia*, deleted a prior requirement that requests for extensions of time for filing a document be submitted three days in advance of the document's due date and replaced it with a requirement that such requests for extensions be submitted on the due date before the official closing time of the receiving office. In that notice, we inadvertently failed to modify paragraph (e)(2) of § 102.65 to delete from it the three day requirement. We now wish to add an amendatory instruction 9 to reflect our intention to delete the three day requirement from this paragraph.

EFFECTIVE DATE: October 28, 1991.

FOR FURTHER INFORMATION CONTACT: John C. Truesdale, Executive Secretary, 1717 Pennsylvania Avenue, NW., room 701, Washington, DC, 20570, Telephone: (202) 254-9430.

§ 102.65 [Amended]

Accordingly, the rule published at 56 FR 49141, September 27, 1991, is corrected on page 49144, third column, by adding new amendatory instruction 9 and the amendment to § 102.65(e)(2) to read as follows:

9. In § 102.65, paragraph (e)(2) is revised to read as follows:

§ 102.65 Motions; interventions.

* * * * *

(e) * * *

(2) Any motion for reconsideration or for rehearing pursuant to this paragraph (e) shall be filed within 14 days, or such further period as may be allowed, after the service of the decision or report. A motion to reopen the record shall be filed promptly on discovery of the evidence sought to be adduced.

* * * * *

Dated, Washington, DC, November 26, 1991.

By direction of the Board:

John C. Truesdale,

Executive Secretary, National Labor Relations Board.

[FR Doc. 91-28928 Filed 12-2-91; 8:45 am]

BILLING CODE 7545-01-M

DEPARTMENT OF THE TREASURY

Office of Foreign Assets Control

31 CFR Part 560

Iranian Transactions Regulations

AGENCY: Office of Foreign Assets Control, Department of the Treasury.

ACTION: Final rule.

SUMMARY: This rule amends the Iranian Transactions Regulations, 31 CFR part 560 (the "Regulations"), to add an interpretation of the documentary requirements for importation of Iranian-origin carpets from third countries and to permit the importation of household and personal effects of Iranian origin by persons arriving in the United States under general license.

EFFECTIVE DATE: December 3, 1991.

FOR FURTHER INFORMATION CONTACT: William B. Hoffman, Chief Counsel (tel.: 202/535-6020), or Steven I. Pinter, Chief of Licensing (tel.: 202/535-9449), Office of Foreign Assets Control, Department of the Treasury, Washington, DC 20220.

SUPPLEMENTARY INFORMATION: This rule amends the Regulations to interpret the requirements of § 560.504 concerning the presentation of documentary evidence of the location of Iranian carpets in third countries prior to the effective date. Specific licensing under § 560.504 is only available for non-fungible goods of Iranian origin. The Office of Foreign Assets Control ("FAC") has determined that documentation indicating solely the size and regional design (Tabriz, Bokhara, etc.) of a carpet is generally insufficient for compliance and enforcement purposes to distinguish the carpet from others of the same size and design. Therefore, FAC will deny license applications that do not provide documentation that identifies the carpet and its location outside Iran since the effective date with sufficient particularity to eliminate the possibility of substitution by another carpet that would not be eligible for importation.

This final rule also amends the Regulations to permit, pursuant to a general license, the importation into the United States of household and personal effects of Iranian origin by persons relocating to the United States from a foreign country. Importation is limited under this general license to no more than five carpets, rugs, or similar articles such as wallhangings or tapestries. If a larger number is attempted to be imported, none may be entered without a specific license from FAC. Given the non-commercial nature of household and personal effects, importations permitted under this general license are unlikely to generate significant foreign exchange earnings for Iran and will assist individuals and households relocating to the United States.

Because the Regulations involve a foreign affairs function, Executive Order 12291 and the provisions of the Administrative Procedure Act, 5 U.S.C. 553, requiring notice of proposed rulemaking, opportunity for public participation, and delay in effective date, are inapplicable. Because no notice of proposed rulemaking is required for this rule, the Regulatory Flexibility Act, 5 U.S.C. 601 *et seq.*, does not apply.

List of Subjects in 31 CFR Part 560

Administrative practice and procedure, Imports, Iran.

For the reasons set forth in the preamble, 31 CFR part 560 is amended as follows:

PART 560—IRANIAN TRANSACTIONS REGULATIONS

1. The authority citation for part 560 continues to read as follows:

Authority: 22 U.S.C. 2349aa-9; E.O. 12613, 52 FR 41940, Oct. 30, 1987.

Subpart D—Interpretations

2. A new § 560.409 is added to read as follows:

§ 560.409 Documentary evidence of the location of Iranian carpets located in third countries prior to the effective date.

(a) Section 560.504 states that specific licenses will be issued to import non-fungible goods of Iranian origin, including carpets, upon submission of satisfactory documentary proof that the goods were located outside Iran prior to the effective date and that no financial benefit will accrue to Iran after the effective date. Section 560.504(c) identifies documents that may serve to satisfy the requirements of this section. Documents submitted must specifically identify the particular item to be imported.

(b) Because of the similarity of carpets of commercial grade, commercial documents which contain only a generic description of a carpet, such as size and style or region of manufacture (*e.g.*, 2.05m. × 1.05m., Tabriz) generally will be insufficient to satisfy the documentary requirement. Documents intended to prove that a particular carpet has been located outside of Iran since the effective date must identify the carpet and its location outside Iran since the effective date with sufficient particularity to eliminate the possibility

of substitution by another carpet that would not be eligible for importation. Accordingly, transportation documents, invoices, inventory lists, or warehouse receipts that provide only general descriptions will not be considered to provide sufficient assurance that a particular carpet has been located outside of Iran since the effective date to justify issuance of a specific license for importation.

Subpart E—Licenses, Authorizations, and Statements of Licensing Policy

3. A new § 560.514 is added to read as follows:

§ 560.514 Importation of household and personal effects authorized.

(a) Except as provided in paragraph (b) of this section, the importation of Iranian-origin goods within the description of household and personal effects under the Harmonized Tariff Schedule of the United States (1991), subheadings 9804.00.05 and 9804.00.20, by persons arriving in the United States from a foreign country is authorized.

(b) This section authorizes the importation of no more than five Iranian-origin carpets, rugs, or similar articles such as tapestries or wallhangings. If a greater number of such items is to be imported, none may be imported without a specific license issued pursuant to this part.

Dated: November 8, 1991.

R. Richard Newcomb,

Director, Office of Foreign Assets Control.

Approved: November 20, 1991.

John P. Simpson,

Acting Assistant Secretary (Enforcement).

[FR Doc. 91-28926 Filed 11-27-91; 12:33 pm]

BILLING CODE 4810-25-M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Health Care Financing Administration

42 CFR Part 411

[BPO-100-FC]

RIN 0938-AF58

Medicare Program; Reporting Requirements for Financial Relationships Between Physicians and Health Care Entities That Furnish Selected Items and Services

AGENCY: Health Care Financing Administration (HCFA), HHS.

ACTION: Interim final rule with comment period.

SUMMARY: This interim final rule sets forth reporting requirements under the Medicare program for the submission by certain health care entities of information about their financial relationships with physicians. It implements section 1877(f) of the Social Security Act, which includes the requirements that entities furnishing Medicare covered clinical laboratory services must provide HCFA with information concerning their ownership arrangements. It also provides notice of HCFA's decision to waive the requirements of section 1877(f) with respect to certain entities that do not furnish clinical laboratory services.

DATES: These regulations are effective December 3, 1991. They are being issued as interim final rules for reasons explained in the Interim Final Regulations section of this preamble. However, we will consider any written comments that are mailed or delivered to the appropriate address, as provided below, and received by 5 p.m. on February 3, 1992.

ADDRESSES: Address written comments to: Health Care Financing Administration, Department of Health and Human Services, Attention: BPO-100-FC, P.O. Box 26676, Baltimore, Maryland 21207.

If you prefer, you may deliver your written comments to one of the following locations:

Room 309-G, Hubert H. Humphrey Building, 200 Independence Avenue, SW., Washington, DC 20201, or

Room 132, East High Rise Building, 6325 Security Boulevard, Baltimore, Maryland 21207.

Due to staffing and resources limitations, we cannot accept audio, video or facsimile (FAX) copies of comments. In commenting, please refer to BPO-100-FC. Comments will be available for public inspection as they are received, beginning approximately three weeks after publication, in room 309-G of the Department's offices at 200 Independence Avenue, SW., Washington, DC 20201, on Monday through Friday of each week from 8:30 a.m. to 5 p.m. (202) 245-7890.

If you wish to submit comments on the information collection requirements contained in this interim final rule, you may submit written comments to: Office of Management and Budget, Office of Information and Regulatory Affairs, Allison Herron Eydt, HCFA Desk Officer, Room 3001, New Executive Office Building, Washington, DC 20503.

FOR FURTHER INFORMATION CONTACT:

Debra Beals, (410) 966-3356. For reporting requirements for all entities other than clinical laboratories.

Ron Smetana, (410) 966-6410. For reporting requirements for clinical laboratories.

SUPPLEMENTARY INFORMATION:

I. Background

A. General

Medicare helps to pay for health care services for eligible beneficiaries in settings and under circumstances described in title XVIII of the Social Security Act (the Act). A common characteristic of most Medicare covered items and services is that they are ordered, prescribed, or performed by a physician or under the direct supervision of a physician. Section 6204 of the Omnibus Budget Reconciliation Act of 1989 (OBRA '89), Public Law 101-239, added section 1877, "Limitation on Certain Physician Referrals," to the Act. Subject to a number of exceptions, section 1877(a) prohibits physicians from making referrals for Medicare covered clinical laboratory services to be furnished by entities with which the physicians have a financial relationship.

Section 4207(e) of the Omnibus Budget Reconciliation Act of 1990 (OBRA '90), Public Law 101-508, amended certain provisions of section 1877 of the Act and of section 6204 of OBRA '89. These laws reflect Congressional concern that physician prescribing patterns and the resultant payment for health care services might be influenced by a physician's financial relationship with the entities that furnish the covered items and services to Medicare beneficiaries.

This interim final rule implements section 1877(f) of the Act, as amended by section 4207(e) of OBRA '90, which requires Medicare providers and suppliers to submit information to HCFA about their ownership arrangements with physicians (and with immediate family members of physicians) and authorizes HCFA to waive the reporting requirement with respect to certain entities. Implementation of the section 1877(a) prohibition on physician referrals for clinical laboratory services will be addressed in a separate **Federal Register** document.

B. Legislative Provisions

As noted above, section 1877(f) of the Act, as included in section 6204 of OBRA '89, set forth broad reporting requirements for providing HCFA with information on the ownership arrangements of each entity providing items or services for which payment may be made under the Medicare program, including information about the covered items and services provided

by the entity and the names and provider numbers of the physicians who are interested investors or the immediate relatives of interested investors. (The term "interested investor" is defined in the statute to include any physician who has a financial relationship with an entity and who is also in a position to make or influence referrals to the entity.) The information was to be submitted no later than December 19, 1990. Entities were required to report the information in the form, manner, and the times specified by the Secretary.

Section 4207(e)(3) of OBRA '90 made a number of modifications. First, it added the requirement that entities report unique identification numbers for physicians instead of the physicians' provider numbers. Second, it delayed the date by which the information is to be reported to October 1, 1991. Third, in section 4207(e)(3)(C), it excepted from the reporting requirements: (a) Medicare covered items and services provided outside the United States; and (b) entities which the Secretary determines provide items and services for which payment may be made under Medicare very infrequently. (Sections 1861(x) and 210(i) of the Act define the United States to include the 50 States, the District of Columbia, the Commonwealth of Puerto Rico, the Virgin Islands, Guam and American Samoa.) Fourth, it also gave the Secretary discretion to waive the reporting requirement, with certain limitations.

The Secretary may not waive the requirement with respect to entities that provide clinical laboratory services. However, the requirement may be waived for other entities in a State, as long as reporting occurs in at least 10 States for at least the following: hospitals, suppliers of ambulance services, entities providing diagnostic imaging services, ESRD facilities, parenteral and enteral suppliers, and entities providing physical therapy services.

Finally, the OBRA '90 amendments to section 1877(f) authorize the Secretary to waive the information collection requirements of the Paperwork Reduction Act (44 U.S.C. chapter 35) with respect to the submission of information by entities other than those that furnish clinical laboratory services.

C. Related Requirements

1. Penalties for Failure to Report Information

Section 1877(g)(5), as added by section 6204(a) of OBRA '89, and amended by section 4207(m)(2) of OBRA '90, provides that any person who is required, but fails, to meet a reporting requirement of section 1877(f) of the Act is subject to a civil money penalty of not more than $10,000 for each day for which reporting is required to have been made. Certain provisions of section 1128A of the Act apply to civil penalties under section 1877(g)(5).

Section 1128B(a) of the Act makes it a criminal offense to knowingly and willfully make or cause to be made any false statement or representation of a material fact for use in determining the right to payment, or to knowingly conceal or fail to disclose events that affect the continued right of payment, with fraudulent intent.

2. Statistical Summary of Comparative Utilization

Section 6204(f) of OBRA '89 directed the Secretary to submit to Congress and the Comptroller General a quarterly report providing a statistical profile (by State and type of service) comparing utilization of services by beneficiaries served by entities in which the referring physician has a direct or indirect financial interest and by beneficiaries served by other entities. Section 4207(e)(4) repealed this requirement and replaced it with a direction to the Secretary to submit a single statistical profile to Congress by June 30, 1992, for the States and entities specified in section 1877(f) (other than entities providing clinical laboratory services).

II. Waiver Determinations

The Secretary has decided to waive the reporting requirements at this time for all entities (other than those providing clinical laboratory services) in States other than the minimum number of ten specified in the statute. In those ten States, the requirement is waived for entities other than those enumerated in the statute. This decision is based on several factors. The waiver represents a balance between the need to obtain sufficient ownership information for meaningful use in developing the statistical profile required by Congress and in evaluating the need for future legislative, policy, or operational actions, and the need to minimize the administrative time and cost involved in collecting and analyzing the information. We believe that by collecting the information from the enumerated entities in the minimum number of ten States, we will satisfy Congressional and administrative needs, and that to expand the activity at this time would not materially benefit the Medicare program.

In determining the States in which a blanket waiver would not be granted, we have selected ten States that represent approximately 42 percent of the physicians who bill the Medicare program for items and services furnished to beneficiaries. Medicare contractors servicing all providers and suppliers in the ten selected States process approximately 40 percent of all Medicare claims. Services provided by the six types of entities specified in the statute account for a significant proportion of Medicare expenditures and represent a cross-section of Medicare covered services. For example, hospitals and ESRD facilities receive the vast majority of payments made under Part A of Medicare. The other types of entities (suppliers of ambulance, physical therapy, diagnostic imaging services and parenteral and enteral supplies) are representative of almost all different types of entities that bill Medicare under Part B of the program.

We believe that a sufficient amount of information can be collected from entities in the selected ten States to develop future policy direction. Information collected from the health care entities in the ten States will be used primarily to prepare the statistical profile for Congress, as required by section 6204(f) of OBRA '89, as amended by section 4207(e)(4) of OBRA '90.

Therefore, we have decided to waive the requirements of section 1877(f) with respect to entities (other than those providing clinical laboratory services) in all States except the following: Arkansas, California, Connecticut, Florida, Michigan, Ohio, Pennsylvania, South Carolina, Texas, and West Virginia. These States were selected because they represent: A mix of rural (e.g., West Virginia), urban (e.g., Florida), and mixed urban/rural States (e.g., Ohio, Texas); a variety of claims/bills volume, from very small (e.g., Arkansas) to very large (e.g., Pennsylvania); and, a geographic spread from north (e.g., Michigan) to south (e.g., South Carolina) as well as both coasts (from California to Connecticut).

All entities that furnish Medicare-covered clinical laboratory services (more than very infrequently) in any State must provide the information required under section 1877(f) and this interim final rule. In addition, the following entities must comply with these reporting requirements if they provide Medicare-covered items or services more than very infrequently in any of the above-listed ten States: Hospitals, suppliers of ambulance services, entities providing diagnostic imaging services, ESRD facilities, parenteral and enteral suppliers, and entities providing physical therapy

services. The reporting requirement is waived for all other health care entities.

Notwithstanding the waiver decisions discussed above, we are considering expanding data collection on ownership arrangements to other States and other types of entities in the future. For example, we are considering collecting information on ambulatory surgical centers (ASCs). These providers have experienced a significant increase in number and service utilization over the past several years in response to the movement of procedures from an inpatient to an outpatient setting. For example, ophthalmology procedures can represent a significant proportion of an ASC's workload. Concerns have been raised about whether various physician financial relationships with ASCs that specialize in ophthalmology procedures have created incentives for increased utilization. Similar concerns have been raised about the possible effects of physicians' ownership interest in suppliers of infusion equipment. We may therefore decide at some future time to withdraw the reporting waiver for such entities in order to collect specific information about their financial relationships with physicians.

We invite public comment on these proposals, suggestions for selecting other health care entities to report financial relationships in the future, as well as whether the information required under this rule should be expanded.

III. Information Required To Be Submitted

A. Financial Relationships

We note several variations in the wording of the reporting requirements as they were enacted in OBRA '89 and modified in OBRA '90. Section 1877(f)(2) as enacted in section 6204 of OBRA '89, required health care entities to report names and Medicare provider numbers of physicians who are "interested investors" or immediate relatives of interested investors. This provision was revised by section 4207(e)(3)(A) of OBRA '90 to require at least the names and Unique Physician Identification Numbers (UPINs) of all physicians with "an ownership or investment interest (as described in subsection (a)(2)(A) (of section 1877) in the entity, or whose immediate relatives have such an ownership or investment interest." Further, in section 4207(e)(4), which concerns the requirement to prepare a statistical profile of physician referral patterns, the statute requires us to examine the utilization of services by beneficiaries served by entities in which the referring physician has a "direct or indirect financial interest." Section 1877(a)(1) prohibits physicians from making referrals for the provision of covered clinical laboratory services to entities in which the referring physician (or a member of his or her immediate family) has a "financial relationship." For these purposes, a financial relationship includes "ownership or investment interests" (through equity, debt, or other means), as described in section 1877(a)(1)(A), as well as "compensation arrangements" (defined to include any arrangement involving any remuneration between a physician or physician's family member and an entity), as described in section 1877(a)(1)(B). Section 1877(g) of the Act provides that no payment may be made under Medicare for a clinical laboratory service which is provided in violation of section 1877(a)(1).

The primary purpose of collecting information under section 1877(f) on the financial relationships of clinical laboratories is to provide us with sufficient information to make payment determinations in accordance with sections 1877 (a) and (g) of the Act. We are, therefore, requiring reporting entities to provide information on all financial relationships they have with physicians or immediate family members of physicians, including ownership, investment, debt, compensation, or any other arrangement involving remuneration of any kind. For entities providing clinical laboratory services, submission of this information is necessary to make payment determinations and is accordingly required under section 1833(e) as well as section 1877(f). (Section 1833(e) of the Act prohibits Medicare Part B payments "unless there has been furnished such information as may be necessary in order to determine the payments due * * *.")

This rule also requires other reporting entities to provide information about all of their financial relationships with physicians and physicians' immediate family members in order to provide HCFA with the data necessary to prepare the statistical profile required under section 6204(f) of OBRA '89, as amended by section 4207(e)(4) of OBRA '90. Because Congress specified that this statistical profile was to cover all "direct or indirect financial interests" of physicians with entities providing services, it would be inconsistent with Congressional intent to limit the information collected to certain categories of financial interest (e.g., to collect information about ownership interests but not about compensation arrangements).

B. Exceptions

The statute provides that certain ownership or investment interests and compensation arrangements do not constitute a "financial relationship" for purposes of the section 1877 prohibition on referrals for clinical laboratory services. The prohibition does not apply to ownership or investment interests described in sections 1877(c) and 1877(d), or to the compensation arrangements described in section 1877(e). (In addition, the prohibition does not apply to referrals for services provided under the circumstances described in section 1877(b), (e.g., in certain group-practice settings) regardless of whether the referring physician has a financial relationship with the entity.)

Since the statute allows for referrals and payments for clinical laboratory services when the financial relationship meets specified requirements, clinical laboratories will not be required to provide the names of physicians whose relationship with the entity (or that of the physician's immediate relatives) is described in sections 1877 (c), (d), and (e).

The following is a summary of these exceptions. Under section 1877(c), the prohibition on referrals does not apply in the case of an ownership of investment securities (including shares or bonds, debentures, notes or other debt instruments) that were purchased on terms generally available to the public and that are in a corporation that meets the following two requirements:

- The corporation is listed for trading on the New York Stock Exchange, or on the American Stock Exchange, or is a national market system security traded under an automated interdealer quotation system operated by the National Association of Securities Dealers.
- At the end of the corporation's most recent fiscal year, its total assets exceeded $100,000,000.

Section 1877(d) provides additional exceptions to the prohibition on physician referrals for an ownership or investment interest in three types of facilities furnishing clinical laboratory services:

- A hospital located in Puerto Rico.
- A laboratory located in a rural area (as defined in section 1886(d)(2)(D)). (Section 1886(d)(2)(D) defines a rural area as an area outside of a "Metropolitan Statistical Area" as that term is defined by the Office of Management and Budget.)
- A hospital located outside of Puerto Rico if the referring physician is

authorized to furnish services at the hospital, and the referring physician's ownership or investment interest is in the hospital itself (and not merely in a subdivision of the hospital).

Section 1877(e) provides that certain compensation arrangements will not trigger the prohibition on physician referrals if specified requirements are met. The first exception applies to the rental or lease of office space that meets all of the following conditions:

• A written agreement must be signed by the parties for the rental or lease of the space. This agreement must—

+ Specify the space covered by the agreement and dedicated for the use of the lessee;

+ Provide for a term of rental or lease of at least 1 year;

+ Provide for payment on a periodic basis of an amount that is consistent with the fair market value as defined in section 1877(h)(3)) of the leased space;

+ Provide for an amount of aggregate payments that does not vary (directly or indirectly) based on the volume or value of any referrals of business between the parties; and

+ Be considered to be commercially reasonable even though no referrals are made between the parties.

• If a physician who is an interested investor (or a physician's immediate family member who is an interested investor) has an ownership or investment interest in the leased or rented office space, the office space must be in the same building as the building in which the physician (or group practice of the physician) has a practice.

• The arrangement must meet all other requirements that the Secretary may impose by regulation as needed to protect against program or patient abuse.

For purposes of meeting these requirements, "fair market value" is defined by section 1877(h)(3) as the value, in arm's-length transactions, consistent with the general market value. With respect to rentals or leases, it means the value of rental property for general commercial purposes (not taking into account its intended use) and not adjusted to reflect the additional value the prospective lessee or lessor would attribute to the proximity or convenience to the lessor when the lessor is a potential source of patient referrals to the lessee.

Under section 1877(e)(2), an arrangement between a hospital and a physician (or a member of the physician's immediate family) for the employment of the physician (or the immediate family member) or for the provision of administrative services would not trigger the prohibition on referrals for clinical laboratory services if the following conditions exist:

• The arrangement is for identifiable services.

• The amount of the remuneration under the arrangement is consistent with the fair market value of the services and is not determined in a manner that takes into account (directly or indirectly) the volume or value of any referrals by the referring physician.

• The remuneration is provided under an agreement that would be commercially reasonable even if no referrals were made to the hospital.

• The arrangement meets all other requirements that the Secretary may impose by regulation as needed to protect against program or patient abuse.

Section 1877(e)(3) provides that remuneration from employment and service arrangements with entities (other than hospitals) that meet all of the following conditions will not cause referrals to the entity for clinical laboratory services to be prohibited:

• The arrangement is for one of four types of services:

+ Specific, identifiable services furnished by a physician as the medical director or as a member of the entity's medical advisory board in order to enable the entity to comply with a Medicare statutory requirement.

+ Specific, identifiable physicians' services furnished to an individual receiving hospice care for which payment may only be made under Medicare as hospice care.

+ Specific physicians' services furnished to a nonprofit blood center.

+ Specific, identifiable, administrative services (other than direct patient care services), but only under exceptional circumstances specified by the Secretary in regulations.

• The amount of the remuneration under the arrangement is—

+ Consistent with the fair market value of the services;

+ Not determined in a manner that takes into account (directly or indirectly) the volume or value of any referrals by the referring physician; and

+ Provided under an agreement that would be commercially reasonable even though no referrals were made.

• The arrangement meets all other requirements that the Secretary may impose by regulation as needed to protect against program or patient abuse.

Section 1877(e)(4) provides the prohibition on physician referrals will not apply to physician recruitment activity by a hospital to induce a physician to relocate to the geographic area served by the hospital to become a member of the hospital's medical staff if the following conditions are met:

• The physician is not required to refer patients to the hospital.

• The amount of the remuneration under the arrangement is not determined in a manner that takes into account (directly or indirectly) the volume or value of any referrals by the referring physician.

• The arrangement meets all other requirements that the Secretary may impose by regulation as needed to protect against program or patient abuse.

Section 1877(e)(5) provides that isolated financial transactions, such as a one-time sale of property, that meet the following conditions will not trigger the prohibition on referrals:

• The amount of the remuneration under the transaction is consistent with the fair market value of the items or services and is not determined in a manner that takes into account (directly or indirectly) the volume or value of any referrals by the referring physician.

• The remuneration is provided under an agreement that would be commercially reasonable even though no referrals were made.

• The arrangement meets all other requirements that the Secretary may impose by regulation as needed to protect against program or patient abuse.

Finally, under section 1877(e)(6), a compensation arrangement involving payment by a group practice of the salary of a physician member of the group practice does not subject the physician to the prohibition on referrals.

Entities that provide clinical laboratory services will not be required to provide the names of physicians whose only financial relationship with the entity satisfies the above requirements.

However, under this regulation, only the provisions of sections 1877(c) will apply to excuse other reporting entities from providing information on any physicians who have financial relationships with the entity (or whose immediate family members have such relationships). For purposes of collecting information from non-clinical laboratory entities in the ten States, we do not believe it would be appropriate or useful to apply the provisions of sections 1877 (d) or (e). Section 1877(d) exceptions apply only to clinical laboratories; therefore, they do not relate to the other health care entities covered by this rule. Section 1877(e) imposes detailed requirements intended to authorize referrals for clinical laboratory services

in specified circumstances. For purposes of collection of information under this rule, application of these provisions to non-clinical laboratory entities that are not subject to the section 1877(f) limitations on physician referrals would not be productive and could eliminate meaningful information on financial relationships between physicians (or immediate family members of physicians) and hospitals, which HCFA needs for purposes of preparing the statistical profile required under OBRA '90. Therefore, entities other than those providing clinical laboratory services will be required to provide the names and UPINs of all such physicians unless the ownership or investment interest is the ownership of investment securities that were purchased on terms generally available to the public in a corporation listed for trading on one of the three major exchanges and the corporation had total assets exceeding $100 million in the most recent fiscal year (section 1877(c)). As discussed in Section V of this Preamble, the survey forms provided to reporting entities will reflect these provisions.

IV. Entities Required to Report

As explained above in section II, we are waiving the section 1877(f) reporting requirements for all health care entities except the following:

- Entities providing Medicare-covered clinical laboratory services within the United States.
- Hospitals, suppliers of ambulance services, entities providing diagnostic imaging services, end stage renal disease (ESRD) facilities, parenteral and enteral suppliers, and entities providing physical therapy services in Arkansas, California, Connecticut, Florida, Michigan, Ohio, Pennsylvania, South Carolina, Texas, and West Virginia.

A. Clinical Laboratories

Federal requirements for laboratories and laboratory services are included in our regulations at 42 CFR part 493 (see 55 FR 9538, March 14, 1990), and became effective September 10, 1990 (except for participation in proficiency testing, which became effective January 1, 1991). Section 493.2 of the regulations defines a laboratory as a facility for the biological, microbiological, serological, chemical, immunohematological, hematological, biophysical, cytological, pathological, or other examination of materials derived from the human body for the purpose of providing information for the diagnosis, prevention, or treatment of any disease or impairment of, or the assessment of the health of, human beings. These examinations also include screening procedures to determine the presence or absence of various substances or organisms in the body. Thus, an "entity furnishing clinical laboratory services" would, for purposes of section 1877(f) and these regulations, be an entity furnishing the services described in § 493.2.

B. Hospitals

All hospitals, as defined in section 1861(e) of the Act, that participate in the Medicare program and that provide services in any of the ten States listed above are subject to the requirements of this regulation.

C. Suppliers of Ambulance Services

Section 410.40 addresses the circumstances under which Medicare part B pays for ambulance services. An ambulance is defined as a vehicle that—

- Is especially designed to transport the sick or injured;
- Contains a stretcher, linens, first aid supplies, oxygen equipment required by State or local laws; and
- Is staffed with personnel trained to provide first aid treatment.

Entities that provide these services in any of the ten States listed above are subject to the requirements of these regulations.

D. Entities Providing Diagnostic Imaging Services

Diagnostic imaging is not a term defined by Medicare statute or by Medicare regulations. It is not a term used by the Medicare program to identify any specific list of services. In general terms a diagnostic image is the result of a procedure that produces representations of organs of the human body. These types of procedures generally fall within the area of radiology services. There are a great number of services that fall under the field of radiology.

However, there are a fixed number of provider types (e.g., hosptials, rehabilitation facility, free-standing Magnetic Resonance Imaging (MRI) facility) which can provide diagnostic imaging services. To identify the entities that provide diagnostic imaging services for purposes of sending them survey forms to complete, we will examine 1990 Medicare claims data. Entities that provided any of the following services in any of the ten designated States will be required to submit ownership information under this regulation: Magnetic Resonance Imaging (MRI), Computerized Axial Tomography (CAT) Scan, and ultrasound services. We believe that entities that provide diagnostic imaging services may be expected to provide at least one of these services, and that this method of identification will be the simplest and the most cost effective approach to obtaining the information required under section 1877(f).

E. ESRD Facilities

ESRD facilities are those entities that meet the requirements spelled out in 42 CFR part 405, subpart U. Section 405.2102 defines an ESRD facility as a facility that is approved to furnish at least one specific ESRD service. The following facilities are ESRD facilities: renal transplantation centers, renal dialysis centers, renal dialysis facilities, self-dialysis units, and special purpose renal dialysis facilities. ESRD facilities providing services in any of the ten designated States are subject to the requirements of these regulations.

F. Parenteral and Enteral Suppliers

Parenteral and enteral suppliers primarily are durable medical equipment suppliers and home health agencies. Covered supplies, equipment and nutrients are the items and services that are determined medically necessary and approved by Medicare for payment. If the coverage requirements for enteral or parenteral nutritional therapy are met, then related supplies, equipment, and nutrients are also covered. Entities that provide such covered services in any of the ten listed States are subject to the requirements of these regulations.

G. Entities Providing Physical Therapy Services

Medicare part B pays for physical therapy services under conditions specified in our regulations at 42 CFR 410.60. Physical therapy includes the assessment and treatment of a patient's rehabilitation needs, therapeutic exercises, gait training, range of motion testing and maintenance therapy for a patient. Entities that provide covered physical therapy services in any of the ten designated States are subject to the provisions of these regulations.

V. Form, Manner, and Timing for Submission of Information

Entities covered by this rule must be prepared to complete a survey on their financial relationships with physicians (defined in section 1861(r) of the Act and HCFA regulations at 42 CFR 410.20) and members of a physician's immediate family. Each reporting entity's fiscal intermediary or carrier will provide the entity with a survey form, which must be completed and returned to the intermediary or carrier. All reporting entities will have at least 30 days in which to return the completed form.

Clinical laboratories will be required to complete either "Hospital and Facility Based Clinical Laboratories with Financial Relationships with Physicians" (Form HCFA–97 for part A billers) or "Clinical Laboratory Financial Relationships with Physicians" (Form HCFA–96 for part B billers), and to submit the completed form to the laboratory's servicing carrier or intermediary. These forms have been approved by the Office of Management and Budget under the Paperwork Reduction Act, 44 U.S.C. chapter 33. They were distributed in late August to entities that furnish Medicare-covered clinical laboratory services. Other health care entities required to report must complete "Survey of Financial Relationships Between Physicians and Selected Health Care Entities" (Form HCFA–95 for both part A and part B billers), and submit the completed form to the carrier or intermediary. Under the authority of section 1877(f), the Paperwork Reduction Act provisions have been waived for this form, and OMB approval is not necessary.

In addition to listing the names and UPINs of physicians who have financial relationships with the entity (or whose family members have such relationships), the entity must include the following types of information: Information that identifies the entity (e.g., name, address, Medicare provider identification/billing number), and information on the type of financial relationship (investment/ownership or compensation) between the entity and physician (or a member of the physician's immediate family).

Entities providing clinical laboratory services will be required to identify certain other information, including the type of laboratory completing the form (i.e., independent, facility-based). Because the forms will also be used to update the information submitted, they will also include a space for specifying the effective date of each physician's financial relationship or that of their immediate relatives. The effective date of the financial relationship is very important. It will assist HCFA in making appropriate payment decisions.

The HCFA forms for reporting clinical laboratories' financial relationships with physicians and/or physicians' immediate family members do not require identification of physicians whose only ownership or investment interest or compensation arrangement qualifies for one of the exceptions specified in section 1877 (c), (d), or (e). It should be noted that section 1877(b) provides additional exceptions to the prohibition on physician referrals for services that are provided under specified circumstances (e.g., by a member of the same group practice as the referring physician, provided certain other requirements are met). The exceptions listed in section 1877(b) relate to the provision of individual services and are not exceptions to the term "financial relationship" under section 1877(a). Other than a general exception contained in paragraph (b)(4) for financial relationships with hospitals which are unrelated to the provision of clinical laboratory services, the application of the section 1877(b) provisions can only be determined and applied on a claim-by-claim basis. Therefore, the section 1877(b) exceptions (other than the one contained in paragraph (b)(4)) are not included on the clinical laboratory survey form. They will be addressed through claims processing modifications. The necessary procedural instructions will be issued through normal HCFA program memoranda and manual issuances prior to January 1, 1992.

Other reporting health care entities will be required to disclose the extent or value of their financial relationships with physicians (or immediate family members of physicians). For example, these entities will be required to identify the approximate percentage of each physician's ownership or investment interest in the entity by indicating the percentage range (.05–5 percent, 5.1–25 percent, more than 25 percent) within which the physician's interest falls.

Health care entities are responsible for obtaining the appropriate forms from their servicing Medicare contractors. To facilitate this process, Medicare contractors will be sending the forms to those entities of record who have billed Medicare for the selected items and services. Non-receipt of a form does not release an entity from the requirement to obtain and complete the required form by the dates specified.

Under these regulations, entities providing clinical laboratory services are required to report changes in their financial relationships (i.e., deletions, accretions) within 60 days from the effective date of the change. It is the clinical laboratory's responsibility to keep this information current. Updates should be reported to the clinical laboratory's servicing Medicare contractor on the appropriate form (i.e., HCFA–96 or HCFA–97).

At this time, we are not requesting that other health care entities covered by this rule submit updates to the information supplied on the first required due date. We will notify the public through notice in the **Federal Register** the next time this information will be required. This decision will be based, in part, on a review of policy alternatives that may result from the statistical profile required by section 4207(e)(4) of OBRA '90.

VI. Provisions of the Regulations

To implement the provisions of OBRA '89 and OBRA '90 discussed above, we will establish a new subpart J under 42 CFR part 411. New subpart J, Physician Ownership of, and Referral of Patients or Laboratory Specimens to Entities Furnishing Clinical Laboratory or Other Health Services, will contain requirements concerning reporting by entities, as well as other provisions relating to physician referrals as contained in section 1877 of the Act. Provisions other than section 1877(f) will be implemented through a separate proposed rule currently under development.

In § 411.1, Basis and scope, we are adding section 1877 as the statutory authority for adding subpart J.

In new § 411.350, Scope of subpart, we describe the statutory authority contained in section 1877.

In new § 411.361, Reporting requirements, we describe in paragraph (a) the basic rule for reporting information (i.e., that, subject to some exceptions, all entities furnishing Medicare-covered clinical laboratory services must provide the information, and that all other health care entities are subject to the requirements unless they receive a waiver). In paragraph (b), we specify the exception to the application of the reporting requirement for entities providing 20 or fewer Part A or Part B items and services during a calendar year. We decided that 20 services annually is an appropriate number to meet the requirements of the Act aimed at excluding entities that bill Medicare only occasionally and, thus, would have at most an insignificant impact on utilization patterns even if all 20 services were for referrals from the same physician. We decided on a fixed number of services rather than some ratio, formula or other reference that would take into account all services (i.e., those not covered under Medicare) to assure accurate application of this exception by reporting entities and Medicare contractors. We establish in paragraph (c) the requirement that we will announce in the **Federal Register** the election to waive reporting requirements as permitted by section 1877(f). Earlier in this preamble, we announced our determination to waive the requirements for all entities other than the following:

• Entities providing Medicare-covered clinical laboratory services anywhere in the United States; and

• Hospitals, suppliers of ambulance services, entities providing diagnostic imaging services, end-stage renal disease (ESRD) facilities, parenteral and enteral suppliers, and entities providing physical therapy services in Arkansas, California, Connecticut, Florida, Michigan, Ohio, Pennsylvania, South Carolina, Texas, and West Virginia.

We describe in paragraph (d) information that must be furnished with respect to financial relationships between an entity and a physician or his/her immediate family member. An entity must submit to its servicing carrier or intermediary at least the name and UPIN of each physician who has a financial relationship with the entity or who has an immediate relative who has such a relationship. We incorporate by reference the definition of "immediate relative" that appears in § 411.12(b) of the regulations, i.e., husband or wife; natural or adoptive parent, child, or sibling; stepparent, stepchild; son-in-law, daughter-in-law, brother-in-law, mother-in-law; grandparent or grandchild; spouse of grandparent or grandchild. In addition, we provide that the entity must describe the nature of the relationship (e.g., ownership or compensation) and the amount of the compensation arrangement or extent of the investment, if HCFA requests that information.

In paragraph (e), we provide that a financial relationship is any ownership or investment interest or any compensation arrangement as those terms are described in section 1877 of the Act.

In paragraph (f), we provide that entities must submit the required information to the entity's servicing carrier or intermediary on a HCFA prescribed form. Forms HCFA-96 and HCFA-97 have already been distributed to entities that furnish Medicare-covered clinical laboratory services. Other entities that are subject to the requirements of this rule will receive a Form HCFA-95 on or after the date this rule is published. All entities will have 30 days from their receipt of the form to provide the initial information. Updated information from clinical laboratories must be submitted within 60 days of the date any change in the entity's financial relationships is effected. As explained earlier, at this time we are not requiring entities other than those furnishing clinical laboratory services to provide updated information. Paragraph (f) also specifies that entities must retain documentation sufficient to verify the information provided, and make that documentation available to us or the OIG in the event we need to verify the data.

In § 411.361(g), we outline civil money penalties for non-reporting. A civil money penalty may be assessed for any person who is required, but fails, to meet the reporting requirements described in this rule. An entity is subject to a civil money penalty of not more than $10,000 for each day after the report is due. Under section 1877(f), submission of the initial report is due October 1, 1991. The imposition of penalties will comply with the applicable provisions of part 1003 of the regulations, Civil Money Penalties and Assessments.

Any person who knowingly and willfully makes a false statement to HCFA could also be subject to criminal liability under section 1128B of the Act. Therefore, entities subject to the reporting requirements of this rule should assure that the deadlines for submission of the information are met and that the information submitted is complete and accurate, including the accurate assertion (self-designation) that the requirements for qualifying for particular exceptions have been met.

In § 411.361(h), we provide that information furnished under this section is disclosable to the public, in accordance with the provisions of part 401 of the Medicare regulations.

VII. Interim Final Regulations

Section 4207(k) of OBRA '90 authorizes the Secretary to issue interim final regulations to implement title IV of OBRA '90 and the amendments made by title IV (Medicare, Medicaid, and other health-related programs). In order to carry out the requirements of section 1877(f) of the Act (as amended by section 4207(e) of OBRA '90); to obtain sufficient information from health care entities in time to apply the Medicare payment provisions of section 1877 (as amended by section 4207(e) of OBRA '90) by the statutory effective date of January 1, 1992; and to facilitate the preparation of the statistical profile required by section 6204(f) of OBRA '89 (as amended by section 4207(e)(4) of OBRA '90) to be submitted to Congress by June 30, 1992, we are exercising this authority to make this rule effective upon publication, with a subsequent 60-day opportunity for public comment. As Congress anticipated in enacting section 4207(j) of OBRA '90, the statutory changes and time constraints imposed under that legislation made publication of a notice of proposed rulemaking prior to the initial implementation of the section 1877(f) requirements impracticable.

We invite public comment on the provisions. Prior to or concurrently with our publication of final regulations implementing the related provisions of section 1877 of the Act, we will publish a final rule addressing the comments that we receive on this interim final rule. As noted above in part I(A) of this preamble, we are developing a separate Notice of Proposed Rulemaking that will be published in the **Federal Register** to address the prohibition on certain physician referrals for clinical laboratory services under section 1877 of the Act. Following our receipt of public comments on that Notice, we will promulgate final regulations under section 1877, including any revisions to this interim final rule that may be appropriate based upon the comments we receive.

VIII. Response to Comments

Because of the large number of items of correspondence we normally receive on a rule, we are not able to acknowledge or respond to them individually. However, we will consider all comments that we receive by the date and time specified in the "DATES" section of this preamble, and we will respond to the comments in the preamble to the final rule, as discussed above in Part VII (Interim Final Regulations).

IX. Regulatory Impact Statement

Executive Order (E.O.) 12291 requires us to prepare and publish an initial regulatory impact analysis for any final requlation that meets one of the E.O. criteria for a "major rule"; that is, that would be likely to result in—

• Annual effect on the economy of $100 million or more;

• A major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions; or,

• Significant adverse effects on innovation, or on the ability of United States-based enterprises in domestic or export markets.

In addition, we generally prepare a regulatory flexibility analysis that is consistent with the Regulatory Flexibility Act (RFA) (5 U.S.C. 601 through 612), unless the Secretary certifies that a regulation will not have a significant economic impact on substantial number of small entities. For purposes of the RFA, we consider all clinical laboratories, hospitals, parenteral and enteral suppliers, and ESRD facilities, suppliers of ambulance services, entities providing physical therapy services, entities providing diagnostic imaging services in certain

States as small entities. Individuals and States are not included in the definition of small entity.

In addition, section 1102(b) of the Act requires the Secretary to prepare a regulatory impact analysis for any final rule that may have a significant impact on the operations of a substantial number of small rural hospitals. This analysis must conform to the provisions of section 604 of the RFA. For purposes of section 1102(b) of the Act, we define a small rural hospital as a hospital with fewer than 50 beds located outside a Metropolitan Statistical area.

This interim final rule sets forth requirements for entities that provide items or services for which payment may be made under Medicare to report certain information to HCFA concerning the entity's financial relationships with physicians and immediate relatives of physicians. Because the rule is not likely to result in a $100 million annual effect on the economy, a major increase in costs or prices, or a significant adverse effect on innovation, we have determined that the threshold criteria for application of E.O. 12291 are not present, and a regulatory impact analysis is not required. Further, we have determined, and the Secretary certifies, that this interim final rule will not have a significant economic impact on a substantial number of small entities and will not have a significant impact on the operations of a substantial number of small rural hospitals. Therefore, we have not prepared a regulatory flexibility analysis.

X. Collection of Information Requirements

Under the authority of section 1877(f) of the Act, as amended by section 4207(e)(3)(C) of OBRA '90, the Secretary has decided to waive the requirements of the Paperwork Reduction Act of 1980 (44 U.S.C. chapter 35) with respect to information required from entities other than those providing clinical laboratory services. This decision is based, in part, on time constraints and on work currently being done within the agency. HCFA is currently exploring the feasibility of reducing the number of data collection instruments used to collect information concerning physician ownership arrangements and it would not be an effective use of resources to obtain clearance for a form that is likely to be used only once. However, should it be necessary to separately survey health care entities (other that those that furnish clinical laboratory services) in the future under section 1877(f) of the Act, we will consider the comments that we receive on this interim final rule and make appropriate revisions to the form based on these comments. Any such revisions (and our response to suggestions that we decline to adopt) will be explained in the preamble to the final rule that will be published following our analysis of the public comments on this interim final rule.

The provisions of the Paperwork Reduction Act have not been waived with respect to the data collection activities applicable to clinical laboratories. Pursuant to those provisions, the Office of Management and Budget (OMB) has approved Form HCFA-96 and Form HCFA-97 for use in collecting financial information from entities providing clinical laboratory services (OMB Approval No. 0938-0586, July 1991).

We estimate that approximately 200,000 forms will be sent by Medicare contractors to entities covered by this rule. On an average, we estimate it will take 30 minutes to complete a form.

List of Subjects in 42 CFR Part 411

Kidney diseases, Medicare, Reporting and recordkeeping requirements.

For reasons set forth in the preamble, 42 CFR part 411 is amended as follows:

PART 411—EXCLUSIONS FROM MEDICARE AND LIMITATIONS ON MEDICARE PAYMENT

1. The authority citation is revised to read as follows:

Authority: Secs. 1102, 1834, 1842(1), 1861, 1862, 1866, 1871, 1877, and 1879 of the Social Security Act (42 U.S.C. 1302, 1395m, 1395u(1), 1395x, 1395y, 1395cc, 1395hh, 1395nn, and 1395pp).

Subpart A—General Exclusions and Exclusion of Particular Services

2. In § 411.1, paragraph (a) is revised to read as follows:

§ 411.1 Basis and scope.

(a) *Statutory basis*. Sections 1814(c), 1835(d), and 1862 of the Act exclude from Medicare payment certain specified services. The Act provides special rules for payment of services furnished by Federal providers or agencies (section 1814(c), and 1835(d)), by hospitals and physicians outside the United States (section 1814(f) and 1862(a)(4)), and by hospitals and SNFs of the Indian Health Services (section 1880). Section 1877 sets forth limitations on physician ownership of, and referrals to, health care entities that furnish clinical laboratory services.

* * * * *

3. In part 411, a new subpart J is added to read as follows and the table of contents is amended accordingly:

Subpart J—Physician Ownership of, and Referral of Patients or Laboratory Specimens to, Entities Furnishing Clinical Laboratory or Other Health Services

§ 411.350 Scope of subpart.

This subpart implements section 1877 of the Act, which generally prohibits a physician from making a referral under Medicare for clinical laboratory services to an entity with which the physician or member of the physician's immediate family has a financial relationship. It also requires, with some exceptions, that entities furnishing covered services under Part A or Part B report information concerning their ownership arrangements in such form, manner and at such times as specified by HCFA.

§ 411.361 Reporting requirements.

(a) *Basic rule*. Except as provided in paragraph (b), the following entities must submit information to HCFA concerning their ownership arrangements in such form, manner, and as such times as HCFA specifies:

(1) All entities that furnish Medicare covered clinical laboratory services within the United States; and

(2) Unless HCFA waives the requirement, as provided in paragraph (c) of this section, all other entities that furnish Part A or Part B items or services within the United States.

(b) *Exception*. The requirements of paragraph (a) of this section do not apply to entities that provide 20 or fewer Part A and Part B items and services during a calendar year.

(c) *Waivers*. Through a document published in the Federal Register, HCFA may waive the requirements of paragraph (a) of this section on a statewide or other basis with respect to entities that do not furnish clinical laboratory services, except that a waiver may not be granted to the following entities in at least ten States: parenteral and enteral suppliers, end stage renal disease facilities, suppliers of ambulance services, hospitals, entities providing physical therapy services, and entities providing diagnostic imaging services.

(d) *Required information*. The information submitted to HCFA under paragraph (a) of this section must include at least the following:

(1) The name and unique physician identification number (UPIN) of each physician who has a financial relationship with the entity;

(2) The name and UPIN of each physician who has an immediate relative (as defined in § 411.12(b)) who

has a financial relationship with the entity;

(3) With respect to each physician identified under paragraphs (d)(1) and (d)(2) of this section, the nature of the financial relationship (including the extent and/or value of the ownership or investment interest or the compensation arrangement, if requested by HCFA).

(e) *Reportable financial relationships.* For purposes of this section, a financial relationship is any ownership or investment interest or any compensation arrangement, as described in section 1877 of the Act.

(f) *Form and timing of reports.* Entities that are subject to the requirements of this section must submit the required information on a HCFA-prescribed form within the time period specified by the servicing carrier or intermediary. All entities will be given at least 30 days from the date of the carrier's or intermediary's request to provide the initial information. Thereafter, entities described in paragraph (a)(1) of this section must provide updated information within 60 days from the date of any change in the information submitted. All entities must retain documentation sufficient to verify the information provided on the forms, and make that documentation available to HCFA or the OIG, upon request.

(g) *Consequences of failure to report.* Any person who is required, but fails, to submit information in accordance with this section is subject to a civil money penalty of up to $10,000 for each day of the period beginning on the day following the applicable deadline established under paragraph (f) of this section until the information is submitted. Assessment of such penalties will comply with the applicable provisions of part 1003.

(h) *Public disclosure.* Information furnished to HCFA under this section is subject to public disclosure in accordance with the provisions of part 401.

(Catalog of Federal Domestic Assistance Program No. 93.774, Supplementary Medical Insurance)

Dated: August 20, 1991.

Gail R. Wilensky,

Administrator, Health Care Financing Administration.

Approved: August 30, 1991.

Louis W. Sullivan,

Secretary.

[FR Doc. 91-28925 Filed 12-2-91; 8:45 am]

BILLING CODE 4120-01-M

DEPARTMENT OF THE INTERIOR

Office of Hearings and Appeals

43 CFR Part 4

RIN 1094-AA40

White Earth Reservation Land Settlement Act of 1985

AGENCY: Office of Hearings and Appeals, Interior.

ACTION: Final rule.

SUMMARY: By notice published in the Federal Register on November 5, 1990, 55 FR 46530, and corrected on November 15, 1990, 55 FR 47831, the Office of Hearings and Appeals proposed to add new regulations for determining, through intestate succession, the heirs of those persons who died entitled to receive compensation pursuant to section 8(c) of the White Earth Reservation Land Settlement Act of 1985, Public Law 99-264 (100 Stat. 61), as amended by Public Law 100-153 (101 Stat. 886) and Public Law 100-212 (101 Stat. 1433). The proposed regulations cited the authority and enunciated the policy and procedures to be followed in making such heirship determinations. The time-sensitive requirements of the White Earth Reservation Land Settlement Act of 1985 made it necessary and desirable for the Secretary to promulgate regulations which would afford efficient and expeditious determination while at the same time maintaining the existing system integrity.

EFFECTIVE DATE: January 2, 1992.

FOR FURTHER INFORMATION: Kathryn A. Lynn, Acting Deputy Director, Office of Hearings and Appeals (703) 235-3816 (not toll free).

SUPPLEMENTARY INFORMATION: The White Earth Reservation Land Settlement Act (WELSA) of 1985, Public Law 99-264, as amended by Public Law 100-153 and Public Law 100-212, provides a method of resolving disputes concerning the title to certain allotments of land on the White Earth Chippewa Indian Reservation in Minnesota. The Act defines circumstances by which title to an allotment may have been lost through a questionable tax forfeiture, sale, mortgage or other taking or transfer during the applicable trust period. The Act directs the Secretary of the Interior to (1) identify the allotments or interests therein which were lost under such circumstances, (2) determine the individuals entitled to compensation for the loss of such allotments or interests therein, (3) ascertain the amount of the compensation to which each such individual is entitled, and (4) pay them such amounts plus interest.

Pursuant to section 8(c) of the Act, it is incumbent upon the Secretary to establish the process whereby the compensation is to be distributed. Writing on behalf of the White Earth Reservation Business Committee on May 20, 1986, the Chairman of that Committee asked that the Office of Hearings and Appeals be made responsible and accountable for determining the heirs of those persons who died entitled to receive compensation under the terms of the Act. This position has the support of the Bureau of Indian Affairs.

Pursuant to this request, proposed regulations were published in the **Federal Register** on November 5, 1990, 55 FR 46530, and corrected on November 15, 1990, 55 FR 47831. Public comments were solicited. No comments were received from persons outside the Department of the Interior. Comments were received from the Office of the Solicitor, Twin Cities Field Office, on behalf of the Bureau of Indian Affairs, and from the administrative judge in the Office of Hearings and Appeals who will be hearing these cases. The following changes have been made to the regulations as proposed in response to the comments received.

Sections 4.350(b) and 4.352(b): Specific references in the regulation to the inheritance laws of Minnesota in effect on March 26, 1986, were deleted. WELSA presently provides that these laws will be applied in making heirship determinations. Prior to March 26, 1986, the Uniform Probate Code was adopted in Minnesota, but the amendment of Minnesota law was not effective until after March 26, 1986. The Uniform Probate Code is more lenient than prior Minnesota law in such areas as inheritance by adopted and illegitimate children. The Department is currently considering seeking a technical amendment that would allow the application of the new State laws of intestate succession. By not specifically stating the date of the law to be applied in the regulation, WELSA could be amended without the necessity of making a corresponding amendment to the regulations. The statutory date will be followed in determining the law to be applied.

In addition, the inclusion of language now requiring the Project Director to request an heirship determination puts the burden of deciding when an heirship determination is needed on the Bureau of Indian Affairs and the Project Director, as provided by WELSA.

Section 4.350(c)(7): A definition of the term "appellant" has been added for clarity.

Section 4.351(a): The introductory phrase was added to underscore that the Project Director must apply recognized existing heirship determinations without review and without further reference to the Office of Hearings and Appeals. This change corresponds with the change made to § 4.350(b).

Section 4.351(b)(1): The acceptable evidence of death was changed to track the language of a similar provision relating to probate of the estates of deceased Indians under 43 CFR 4.210.

Section 4.351(b)(3): One change would allow recognized determinations of the heirs of other related decedents to be submitted as evidence in an heirship determination. A second change would clarify that what is intended is to recognize at least as evidence the decisions of whatever court-like forum is vested with the authority to determine heirs in other countries.

Section 4.351(b)(4): The term "interested" is changed to "interest" to correct a printing error.

Section 4.352(b)(1): The time for filing a response as to why a preliminary determination should not become final was increased to forty (40) days in order to allow a reasonable opportunity for response by persons who receive notice through posting. Administrative matters preliminary to posting could substantially reduce the time available for responses from those persons who received notice through posting. A requirement was added that the administrative judge shall cause a certificate to be made as to the date and manner by which the preliminary determination was mailed in order to ensure the completeness of the administrative record. A corresponding change was made to § 4.352(b)(3).

Section 4.352(b)(2): The section was changed in order to give the Project Director two additional days in which to accomplish posting and to give him discretion to determine the places in which posting should occur. The burden of determining appropriate hearing sites should rest with the Project Director, rather than with the Office of Hearings and Appeals because of the Project Director's greater familiarity with families and the area. Although it was suggested that the list of possible posting locations might be deleted, it was believed that such a list would provide notice to individuals affected of the places where they might reasonably expect to find posted notices. It is expected that the Project Director will develop specific, written guidelines for determining appropriate posting sites.

In addition, the section was amended to track 43 CFR 4.211(a) in requiring that a posting certificate be signed by the person posting and returned to the Project Director. Because the originals of all documents evidencing proper posting should be part of the official administrative record, the section was also amended to require that all such documents be forwarded to the administrative judge. A corresponding change, requiring these documents to be made part of the official record, was made to § 4.353(b)(1).

Section 4.353(a): The term "his" is changed to "the" to remove a gender-based pronoun.

Section 4.353(b)(1): Refer to discussion under § 4.352(b)(2).

Section 4.354: The term "person" in the first sentence was changed to "party" for consistency of usage throughout the regulations.

Paperwork Reduction Act

This rule does not contain information collection requirements that require approval by the Office of Management and Budget under 44 U.S.C. 3501 *et seq.*

Executive Order 12291 and Regulatory Flexibility Act

The Department of the Interior has determined this document is not a major rule under Executive Order 12291 (Feb. 17, 1981), and certifies this document will not have a significant economic effect on a substantial number of small entities under the Regulatory Flexibility Act, 5 U.S.C. 601 *et seq.* These determinations are based on the fact that the rule only sets forth procedures for such heirship determinations as are necessary in order to determine who should receive compensation under the White Earth Reservation Land Settlement Act of 1985, as amended.

National Environmental Policy Act

This rulemaking is categorically excluded from the National Environmental Policy Act of 1969, as amended, 42 U.S.C. 4321 through 4347, process because it is of an administrative, financial, legal, technical, and procedural nature, and therefore neither an environmental assessment nor an environmental impact statement is required. 40 CFR 1508.4; 516 DM 2.3A.

Takings Implication Assessment

The rules do not pose any takings implications requiring preparation of a Takings Implication Assessment under Executive Order No. 12630 of March 18, 1988.

Drafting

The primary author of this rule is Howard Piepenbrink, Chief, Branch of Titles and Research, Bureau of Indian Affairs, U.S. Department of the Interior.

List of Subjects in 43 CFR Part 4

Administrative practice and procedure, Indians.

Accordingly, 43 CFR part 4, subpart D, is amended as set forth below.

Dated: October 3, 1991.

John Schrote,

Assistant Secretary — Policy, Management and Budget.

PART 4—[AMENDED]

Subpart D—Rules Applicable in Indian Affairs Hearings and Appeals

1. The authority for 43 CFR part 4, subpart D, is revised to read as follows:

Authority: Secs. 1, 2, 36 Stat. 855, as amended, 856, as amended, sec. 1, 38 Stat. 586, 42 Stat. 1185, as amended, secs. 1, 2, 56 Stat. 1021, 1022; R.S. 463, 465; 5 U.S.C. 301; 25 U.S.C. secs. 2, 9, 372, 373, 374, 373a, 373b; 100 Stat. 61, as amended by 101 Stat. 886 and 101 Stat. 1433, 25 U.S.C. 331 note.

2. New sections 4.350 through 4.357, and a new center heading, are added to subpart D to read as follows:

White Earth Reservation Land Settlement Act of 1985; Authority of Administrative Judges; Determinations of the Heirs of Persons Who Died Entitled to Compensation

White Earth Reservation Land Settlement Act of 1985; Authority of Administrative Judges; Determinations of the Heirs of Persons Who Died Entitled to Compensation

§ 4.350 Authority and scope.

(a) The rules and procedures set forth in §§ 4.350 through 4.357 apply only to the determination through intestate succession of the heirs of persons who died entitled to receive compensation under the White Earth Reservation Land Settlement Act of 1985, Public Law 99–264 (100 Stat. 61), amended by Public Law 100–153 (101 Stat. 886) and Public Law 100–212 (101 Stat. 1433).

(b) Whenever requested to do so by the Project Director, administrative

judges shall determine such heirs by applying inheritance laws in accordance with the White Earth Reservation Land Settlement Act of 1985 as amended, notwithstanding the decedent may have died testate.

(c) As used herein, the following terms shall have the following meanings:

(1) The term *Act* means the White Earth Reservation Land Settlement Act of 1985 as amended.

(2) The term *Board* means the Board of Indian Appeals in the Office of Hearings and Appeals, Office of the Secretary.

(3) The term *Project Director* means the officer in charge of the White Earth Reservation Land Settlement Branch of the Minneapolis Area Office, Bureau of Indian Affairs, at Cass Lake, Minnesota.

(4) The term *party (parties) in interest* means the Project Director and any presumptive or actual heirs of the decedent, or of any issue of any subsequently deceased presumptive or actual heir of the decedent.

(5) The term *compensation* means a monetary sum, as determined by the Project Director, pursuant to section 8(c) of the Act.

(6) The term *administrative judge* means an administrative judge of the Office of hearings and Appeals to whom the Director of the Office of Hearings and Appeals has redelegated his authority, as designee of the Secretary, for making heirship determinations as provided for in these regulations.

(7) The term *appellant* means a party aggrieved by a final order or final order upon reconsideration issued by an administrative judge who files an appeal with the Board.

§ 4.351 Commencement of the determination process.

(a) Unless an heirship determination which is recognized by the Act already exists, the Project Director shall commence the determination of the heirs of those persons who died entitled to receive compensation by filing with the administrative judge all data, identifying the purpose for which they are being submitted, shown in the records relative to the family of the decedent.

(b) The data shall include but are not limited to:

(1) A copy of the death certificate if one exists. If there is no death certificate, then another form of official written evidence of the death such as a burial or transportation of remains permit, coroner's report, or church registry of death. Secondary forms of evidence of death such as an affidavit from someone with personal knowledge concerning the fact of death or an obituary of death notice from a newspaper may be used only in the absence of any official proof or evidence of death.

(2) Data for heirship finding and family history, certified by the Project Director. Such data shall contain:

(i) The facts and alleged facts of the decedent's marriages, separations and divorces, with copies of necessary supporting documents;

(ii) The names and last know addresses of probable heirs at law and other know parties in interest;

(iii) Information on whether the relationships of the probable heirs at law to the decedent arose by marriage, blood, or adoption.

(3) Known heirship determinations, including those recognized by the Act determining the heirs of relatives of the decedent, and including those rendered by courts from Minnesota or other states, by tribal courts, or by tribunals authorized by the laws of other countries.

(4) A report of the compensation due the decedent, including interest calculated to the date of death of the decedent, and an outline of the derivation of such compensation, including its real property origins and succession of the compensation to the deceased, citing all of the intervening heirs at law, their fractional shares, and the amount of compensation attributed to each of them.

(5) A certification by the Project Director or his designee that the addresses provided for the parties in interest were furnished after having made a due and diligent search.

§ 4.352 Determination of administrative judge and notice thereof.

(a) Upon review of all data submitted by the Project Director, the administrative judge will determine whether or not there are any apparent issues of fact that need to be resolved.

(b) If there are no issues of fact requiring determination, the administrative judge will enter a preliminary determination of heirs based upon inheritance laws in accordance with the Act. Such preliminary determination will be entered without a hearing, and, when possible and based upon the data furnished and/or information supplementary thereto, shall include the names, birth dates, relationships to the decedent, and shares of the heirs, or the fact that the decedent died without heirs.

(1) Upon issuing a preliminary determination, the administrative judge shall issue a notice of such action and shall mail a copy of said notice, together with a copy of the preliminary determination, to each party in interest allowing forty (40) days in which to show cause in writing why the determination should not become final. The administrative judge shall cause a certificate to be made as to the date and manner of such mailing.

(2) The Project Director shall also cause, within seven (7) days of receipt of such notice, the notice of the preliminary determination to be posted in the following sites:

The White Earth Band, Box 418, White Earth, Minnesota 56591
The Minnesota Chippewa Tribe, Box 217, Cass Lake, Minnesota 56633
Minnesota Agency, Bureau of Indian Affairs, Route 3, Box 112, Cass Lake, Minnesota 56633

and in such other sites as may be deemed appropriate by the Project Director. Such other sites may include, but not be limited to:

Elbow Lake Community Center, R.R. ι2, Waubun, Minnesota 56589
Postmaster, Callaway, Minnesota 56521
Community Center, Route 2, Bagley, Minnesota 56621
Community Center, Star Route, Mahnomen, Minnesota 56557
Postmaster, Mahnomen, Minnesota 56557
Rice Lake Commuinity Center, Route 2, Bagley, Minnesota 56621
Postmaster, Ogema, Minnesota 56569
Pine Point Community Center, Ponsford, Minnesota 56575
Postmaster, White Earth, Minnesota 56591
White Earth IHS, White Earth, Minnesota 56591
Postmaster, Ponsford, Minnesota 56575
American Indian Center, 1113 West Broadway, Minneapolis, Minnesota 55411
American Indian Center, 1530 East Franklin Avenue, Minneapolis, Minnesota 55404
American Indian Center, 341 University Avenue, St. Paul, Minnesota 55103
Little Earth of United Tribes Community Services, 2501 Cedar Avenue South, Minneapolis, Minnesota 55404
Naytahwaush Community Center, Naytahwaush, Minnesota 56566

The Project Director shall provide a certificate showing when the notice of the preliminary determination was forwarded for posting, and to which locations. A posting certificate showing the date and place of posting shall be signed by the person or official who performs the act and returned to the Project Director. The Project Director shall file with the administrative judge the original posting certificates and the Project Director's certificate of mailing showing the posting locations and when the notice of the preliminary determination was forwarded for posting.

(3) If no written request for hearing or written objection is received in the office of the administrative judge within

the forty (40) days of issuance of the notice, the administrative judge shall issue a final order declaring the preliminary determination to be final thirty (30) days from the date on which the final order is mailed to each party in interest.

(c) When the administrative judge determines either before or after issuance of a preliminary determination that there are issues which require resolution, or when a party objects to the preliminary determination and/or requests a hearing, the administrative judge may either resolve the issues informally or schedule and conduct a prehearing conference and/or a hearing. Any prehearing conference, hearing, or rehearing, conducted by the administrative judge shall be governed insofar as practicable by the regulations applicable to other hearings under this part and the general rules in subpart B of this part. After receipt of the testimony and/or evidence, if any, the administrative judge shall enter a final order determining the heirs of the decedent, which shall become final thirty (30) days from the date on which the final order is mailed to each party in interest.

(d) The final order determining the heirs of the decedent shall contain, where applicable, the names, birth dates, relationships to the decedent, and shares of heirs, or the fact that the decedent died without heirs.

§ 4.353 Record.

(a) The administrative judge shall lodge the original record with the Project Director.

(b) The record shall contain, where applicable, the following materials:

(1) A copy of the posted public notice of preliminary determination and/or hearing showing the posting certifications, the administrative judge's certificate of mailing, the posting certificates, and the Project Director's certificate of mailing.

(2) A copy of each notice served on parties in interest, with proof of mailing;

(3) The record of evidence received, including any transcript made of testimony;

(4) Data for heirship finding and family history, and data supplementary thereto;

(5) The final order determining the heirs of the decedent and the administrative judge's notices thereof; and

(6) Any other material or documents deemed relevant by the administrative judge.

§ 4.354 Reconsideration or rehearing.

(a) Any party aggrieved by the final order of the administrative judge may, within thirty (30) days after the date of mailing such decision, file with the administrative judge a written petition for reconsideration and/or rehearing. Such petition must be under oath and must state specifically and concisely the grounds upon which it is based. If it is based upon newly discovered evidence, it shall be accompanied by affidavits of witnesses stating fully what the new evidence or testimony is to be. It shall also state justifiable reasons for the prior failure to discover and present the evidence.

(b) If proper grounds are not shown, or if the petition is not filed within the time prescribed in paragraph (a) of this section, the administrative judge shall issue an order denying the petition and shall set forth therein the reasons therefor. The administrative judge shall serve copies of such order on all parties in interest.

(c) If the petition appears to show merit, or if the administrative judge becomes aware of sufficient additional evidence to justify correction of error even without the filing of a petition, or upon remand from the Board following an appeal resulting in vacating the final order, the administrative judge shall cause copies of the petition, supporting papers, and other data, or in the event of no petition an order to show cause or decision of the Board vacating the final order in appropriate cases, to be served on all parties in interest. The parties in interest will be allowed a reasonable, specified time within which to submit answers or legal briefs in opposition to the petition or order to show cause or Board decision. The administrative judge shall then reconsider, with or without hearing, the issues of fact and shall issue a final order upon reconsideration, affirming, modifying, or vacating the original final order and making such further orders as are deemed warranted. The final order upon reconsideration shall be served on all parties in interest and shall become final thirty (30) days from the date on which it is mailed.

(d) Successive petitions for reconsideration and/or rehearing shall not be permitted. Nothing herein shall be considered as a bar to the remand of a case by the Board for further reconsideration, hearing, or rehearing after appeal.

§ 4.355 Omitted compensation.

When, subsequent to the issuance of a final order determining heirs under § 4.352, it is found that certain additional compensation had been due the decedent and had not been included in the report of compensation, the report shall be modified administratively by the Project Director. Copies of such modification shall be furnished to all heirs as previously determined and to the appropriate administrative judge.

§ 4.356 Appeals.

(a) A party aggrieved by a final order of an administrative judge under § 4.352, or by a final order upon reconsideration of an administrative judge under § 4.354, may appeal to the Board (address: Board of Indian Appeals, Office of Hearings and Appeals, 4015 Wilson Boulevard, Arlington, Virginia 22203). A copy of the notice of appeal must also be sent to the Project Director and to the administrative judge whose decision is being appealed.

(b) The notice of appeal must be filed with the Board no later than thirty (30) days from the date on which the final order of the administrative judge was mailed, or, if there has been a petition for reconsideration or rehearing filed, no later than thirty (30) days from the date on which the final order upon reconsideration of the administrative judge was mailed. A notice of appeal that is not timely filed will be dismissed.

(c) The Project Director shall ensure that the record is expeditiously forwarded to the Board.

(d) Within thirty (30) days after the notice of appeal is filed, the appellant shall file a statement of the reasons why the final order or final order upon reconsideration is in error. If the Board finds that the appellant has set forth sufficient reasons for questioning the final order or final order upon reconsideration, the Board will issue an order giving all parties in interest an opportunity to respond, following which a decision shall be issued. If the Board finds that the appellant has not set forth sufficient reasons for questioning the final order, the Board may issue a decision on the appeal without further briefing.

(e) The Board may issue a decision affirming, modifying, or vacating the final order or final order upon reconsideration. A decision on appeal by the Board either affirming or modifying the final order or final order upon reconsideration shall be final for the Department of the Interior. In the event the final order or final order upon reconsideration is vacated, the proceeding shall be remanded to the appropriate administrative judge for reconsideration and/or rehearing.

§ 4.357 Guardians for minors and incompetents.

Persons less than 18 years of age and other legal incompetents who are parties in interest may be represented at all hearings by legally appointed guardians or by guardians *ad litem* appointed by the administrative judge.

FR Doc. 91-28904 Filed 12-2-91, 8:45 am]

BILLING CODE 4310-79-M

DEPARTMENT OF TRANSPORTATION

National Highway Traffic Safety Administration

49 CFR Part 571

[Docket No. 91-13; Notice 2]

RIN 2127-AD85

Federal Motor Vehicle Safety Standards; Motorcycle Controls and Displays

AGENCY: National Highway Traffic Safety Administration (NHTSA), DOT.

ACTION: Final rule.

SUMMARY: This final rule amends Federal Motor Vehicle Safety Standard No. 123, *Motorcycle controls and displays*, by removing restrictions on the orientation of the axis of rotation for manual fuel shutoff controls on motorcycles. This final rule makes no change in the existing requirement that the controls operate by being rotated. It also makes no change in the existing requirement that the control positions ("On," "Off," and if provided, "Reserve") be separated by 90 degrees of rotation. However, it does eliminate other restrictions on the location of those control positions. This final rule will provide manufacturers with additional design flexibility without affecting safety.

DATES: *Effective Date:* This final rule is effective January 2, 1992.

Petitions for Reconsideration: Any petitions for reconsideration of this rule must be received by NHTSA no later than January 2, 1992.

ADDRESSES: Petitions for reconsideration must refer to the docket and notice numbers set forth at the beginning of this notice and be submitted to the following: Administrator, National Highway Traffic Safety Administration, 400 Seventh Street, SW., Washington, DC 20590. Docket hours are 9:30 a.m. to 4 p.m., Monday through Friday. It is requested, but not required, that 10 copies of the petition be submitted.

FOR FURTHER INFORMATION CONTACT: Mr. Jere Medlin, Office of Vehicle Safety Standards, NRM-11, NHTSA, 400 Seventh Street, SW., Washington, DC 20590. Mr. Medlin's telephone number is (202) 366-5276.

SUPPLEMENTARY INFORMATION:

Background

Federal Motor Vehicle Safety Standard No. 123, *Motorcycle controls and displays*, (49 CFR 571.123) specifies requirements for the location, operation, identification, and illumination of motorcycle controls and displays. Currently, Table 1 of Standard No. 123 requires that manual fuel shutoff controls on motorcycles rotate around a transverse or longitudinal axis and that the modes of operation ("Off", "On" and if provided, "Reserve On") be identified at appropriate points around that axis. This current specification is a result of a final rule published on September 7, 1984 (49 FR 35380). In the September 1984 final rule, the agency determined that motor vehicle safety was best served by retaining the standardization of control position relationships while amending the standard to allow manufacturers to place the control so that it may operate in its required positions around either a longitudinal or transverse axis. The control was previously required to operate around a transverse axis.

By a petition dated November 14, 1990, the Motorcycle Industry Council (MIC) petitioned the agency to amend Standard No. 123 to permit the manual fuel shutoff controls on motorcycles to rotate around any axis, provided that the relationship of the control positions (i.e. "On", "Off", and, if provided "Reserve") to each other remained the same as required by the current standard. MIC stated as its rationale for the petition that the mechanical components on many of today's motorcycles are enclosed in streamlined bodies. MIC asserted that since few parts of streamlined bodies follow the longitudinal or transverse axes of the motorcycle, "special provisions" must be made in the design of the body in order to comply with Standard No. 123. MIC stated that this restricts manufacturer's freedom of design. On March 1, 1991, NHTSA granted MIC's petition.

Notice of Proposed Rulemaking and Public Comment

Following its grant of MIC's petition, NHTSA published, on June 27, 1991 (56 FR 29451), a notice of proposed rulemaking (NPRM) that proposed to amend Standard No. 123 to remove restrictions on the orientation of the axis of rotation for manual fuel shutoff controls on motorcycles. In the NPRM, NHTSA tentatively concluded that there is no safety-related justification for restricting the design of manual fuel shutoff controls to a longitudinal or transverse axis. Among other factors, the agency noted that although the axis orientation is standardized, there is no location requirement for the control itself, nor a requirement that the control even be provided.

However, that agency also tentatively concluded that the requirements for standardization of the relationship between the control positions ("On", "Off", and of provided, "Reserve") are a necessary crash avoidance requirement. This is because standardization of control positions enables the operator to use the control without taking his or her eyes off the road. The agency therefore proposed to retain the requirement that the control operate by rotating. NHTSA further proposed to retain the requirement that the "Off" and "On" positions be separated by 90 degrees of rotation and that the "Off" and, if provided, "Reserve" positions be separated by 90 degrees of rotation. The proposed sequence of controls was "On"—"Off"—"Reserve".

NHTSA did not propose to adopt MIC's suggestion for the sequence of the control positions because of the workability of MIC's sequence was premised on the existence of a "Reserve" position. The agency stated that although it was not aware of a shutoff control that lacks a "Reserve" position, Standard No. 123 does not require a "Reserve" position.

In response to the NPRM, the agency received one comment, from American Honda Motor Company, Inc. Honda wrote in favor of the added design flexibility that the NPRM would provide and agreed with NHTSA's conclusion that there is no safety need to require that manual fuel shutoff controls operate around a longitudinal or transverse axis.

Final Rule

Since the public comment for Honda favored the changes proposed in the notice of proposed rulemaking and the agency received no other comment, NHTSA adopts as final the tentative conclusions and proposed regulatory text set forth in the NPRM.

Effective Date

Because this final rule relieves restrictions and is optional in nature, the agency has concluded that this rule should become effective sooner than 180 days after the issuance of this rule. Therefore, the agency finds for good cause that this rule should become effective 30 days after it is published.

Regulatory Impacts

Executive Order 12291 (Federal Regulation) and DOT Regulatory Policies and Procedures

NHTSA has analyzed this rule and determined that it is neither "major" within the meaning of Executive Order 12291 nor "significant" within the meaning of Department of Transportation regulatory policies and procedures. The rule does not impose any additional requirements. Instead, it permits manufacturers greater flexibility in the design and location of manual fuel shutoff controls. The agency has determined that the economic effects of this rule are so minimum that a full regulatory evaluation is not required.

The agency has also considered the effects of this rulemaking under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) I certify that this final rule will not have a significant economic impact on a substantial number of small entities. The rationale for this certification is that the rule imposes no requirements and relieves restrictions on the axis of rotation for motorcycle manual fuel control sequence. Also, small organizations and governmental jurisdictions purchasing new motorcycles will not be affected since the cost of motorcyles will, at most, be negligibly affected by this final rule.

This action has been analyzed in accordance with the principles and criteria contained in Executive Order 12612. It has been determined that the final rule does not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

In accordance with the National Environmental Policy Act, NHTSA has considered the environmental impacts of this rule and determined that it will not have a significant impact on the quality of the human environment.

List of Subjects in 49 CFR Part 571

Imports, Motor vehicle safety, Motor vehicles, Rubber and rubber products, Tires.

In consideration of the foregoing, 49 CFR 571.123 is amended as follows:

PART 571—[AMENDED]

1. The authority citation for part 571 continues to read as follows:

Authority: 15 U.S.C. 1392, 1401, 1403, 1407; delegation of authority at 49 CFR 1.50.

§ 571.123 [Amended]

2. The operation requirements for the manual fuel shutoff control (item 7) in column 3 of table 1 of Standard No. 123 is revised to read as follows:

Rotate to operate. "On" and "Off" are separated by 90 degrees of rotation. "Off" and "Reserve" (if provided) are separated by 90 degrees of rotation. Sequence order: "On"—"Off"—"Reserve".

* * * * *

Issued on: November 26, 1991.

Jerry Ralph Curry,

Administrator.

[FR Doc. 91-28869 Filed 12-2-91; 8:45 am]

BILLING CODE 4910-59-M

INTERSTATE COMMERCE COMMISSION

49 CFR Part 1152

[Ex Parte No. 274 (Sub-No. 22)]

Abandonment Proceedings: Use of URCS in the Calculation of Off-Branch Costs

AGENCY: Interstate Commerce Commission.

ACTION: Final rules.

SUMMARY: In its decision in Uniform Railroad Costing System, 5 I.C.C.2d 894 (1989), the Commission adopted the Uniform Railroad Costing System (URCS) as the preferred general purpose costing system that would supplant Rail Form A for all regulatory purposes where general purpose costs were appropriate. Now, the Commission is adopting a final rule, applicable to abandonment application proceedings, specifying precisely how URCS is to be used in the calculation of off-branch costs. The final rule is being adopted without the usual opportunity for notice and comment because the revisions merely provide an explanation of the proper utilization of URCS in the off-branch cost calculation procedure.

EFFECTIVE DATE: The final rule shall become effective on December 3, 1991.

FOR FURTHER INFORMATION CONTACT: William T. Bono, (202) 275-7354; James R. Wells, (202) 275-7548 (TDD for hearing impaired: (202) 275-1721).

SUPPLEMENTARY INFORMATION: Additional information is contained in the Commission's decision. To obtain a copy of the full decision, write to, call, or pick up in person from: Dynamic Concepts, Inc., room 2229, Interstate Commerce Commission Building, Washington, DC 20423. Telephone: (202) 275-4357/4359. (Assistance for the hearing impaired is available through TDD services (202) 275-1721.)

This action will not significantly affect either the quality of the human environment or the conservation of energy resources.

This action will have no significant effect on a substantial number of small entities.

List of Subjects in 49 CFR Part 1152

Administrative practice and procedure, Conservation, Environmental protection, National forests, National parks, National trails system, National resources, Public lands—grants, Public lands—rights-of-way, Railroads, Recreation and recreation areas, Reporting and recordkeeping requirements.

Decided: November 22, 1991.

By the Commission, Chairman Philbin, Vice Chairman Emmett, Commissioners Simmons, Phillips, and McDonald.

Sidney L. Strickland, Jr.,

Secretary.

For the reasons set forth in the preamble, title 49, chapter X, part 1152 of the Code of Federal Regulations is amended as follows:

PART 1152—ABANDONMENT AND DISCONTINUANCE OF RAIL LINES AND RAIL TRANSPORTATION UNDER 49 U.S.C. 10903

1. The authority citation for part 1152 continues to read as follows:

Authority: 5 U.S.C. 553, 559, and 704; 11 U.S.C. 1170; 16 U.S.C. 1247(d) and 1248; and 49 U.S.C. 10321, 10362, 10505, 10903, 10904, 10905, 10906, 11161, and 11163.

2. Section 1152.2 is amended by revising paragraph (m) to read as follows:

§ 1152.2 Definitions.

* * * * *

(m) *URCS* means the Uniform Railroad Costing System.

* * * * *

3. Section 1152.31 is amended by revising paragraph (a)(1) to read as follows:

§ 1152.31 Revenue and income attributable to branch lines.

* * * * *

(a) * * *

(1) Originates and terminates on the branch;

* * * * *

4. Section 1152.32 is amended by revising paragraph (n) to read as follows:

§ 1152.32 Calculation of avoidable costs.

* * * * *

(n) *Off-branch costs.* The off-branch costs developed in this section shall be separated between "off-branch costs other than return on freight cars" and "return on value-freight cars". The off-

branch costs shall be developed in the following manner:

(1) Terminal costs, line-haul costs, interchange costs, and modified terminal costs shall be considered as the off-branch avoidable costs of providing service over the remainder of the railroad's system. These costs shall be computed by applying the variable unit costs to the service units attributed to the branch line's traffic for the time periods specified in § 1152.22(d) of this part.

(2) The procedure for determining the off-branch costs shall be based upon the URCS cost formula. This formula shall be applied to the latest Annual Report Form R-1 filed by the railroad, with two exceptions. First, the amount used in the formula for freight car depreciation shall be calculated using the procedure discussed in paragraph (g)(3)(iii) of this section applied to the average total car fleet of the railroad. Second, the return on investment in freight cars shall be computed using the procedure set forth in paragraph (g)(3)(ii) of this section. In addition, the application of URCS shall include the use of the nominal cost of capital for all return on investment determinations.

(3) *The Class I Procedure:* A Class I railroad shall calculate its off-branch costs using the Class I procedure set forth in this paragraph (n)(3).

(i) The unit costs developed by applying URCS in the manner specified in paragraph (n)(2) of this section shall be applied to the service characteristics of each movement of traffic that is attributed to the branch line. This application shall result in the total off-branch cost associated with this traffic for normal terminal handlings, line-haul mileage, and interchange events.

(ii) The modified terminal cost per carload shall be calculated separately for each type of freight car and applied to each car that is attributed to the branch line. The modified terminal cost shall consist of clerical costs, two days of freight car cost, and an inter-intra train switching cost (locomotive engine minute cost only). The clerical cost and inter-intra train switching cost shall be calculated from unit costs developed within the individual URCS application.

(A) The unit costs for the clerical cost per carload calculation are located in Worktable E1, Part 1: Line 106, columns 1, 2, and 3; line 107, column 1; line 108, column 1; line 109, column 1; and line 110, column 1.

(B) The inter-intra train switching cost shall be calculated by multiplying the total switch engine minute cost from Worktable E1, part 1, line 111, columns 1, 2, and 3 by the total minutes specified in the next sentence. The total minutes specified in this sentence shall equal the sum of:

(1) The minutes per switch event from Worktable E2, Part 1, line 118, column 29; and

(2) The product of the minutes per switch event from Worktable E2, Part 1, line 118, column 29 and the ratio of loaded to total car miles for the particular type of freight car being costed.

(C) The freight car cost shall be the car ownership costs per car day for two days developed in accordance with the procedures set forth in paragraph (g)(3) of this section for the type of freight car being costed.

(iii) For a Class I railroad, the total costs calculated using the procedures set forth in paragraphs (n)(3)(i) and (n)(3)(ii) of this section shall constitute the off-branch costs attributable to the branch line's traffic.

(4) A Class II or Class III railroad shall calculate its off-branch costs using any one of three different procedures. The Class I Procedure: A Class II or Class III railroad may calculate its off-branch costs using the Class I procedure set forth in paragraph (n)(3) of this section, if the necessary data are available from the railroad's own records. If the data necessary to complete the Class I procedure set forth in paragraph (n)(3) of this section are not available from the railroad's own records, the Class II or Class III railroad shall calculate its off-branch costs using either one of the following procedures based on the latest regional URCS data and the railroad's own records. The Class II/III Simplified Costing Procedure: A Class II or Class III railroad may calculate its off-branch costs using the Class I procedure set forth in paragraph (n)(3) of this section, with regional URCS data of the Class I railroads used in lieu of individual URCS data of the Class II or Class III railroad. Costs developed through the use of the Class II/III simplified costing procedure shall enjoy a rebuttable presumption of correctness. The Class II/III Standard Costing Procedure: A Class II or Class III railroad may calculate its off-branch costs using the Class II/III standard costing procedure set forth in paragraphs (n)(4)(i) through (n)(4)(xiv) of this section. Costs developed through the use of the Class II/III standard costing procedure shall be given preference over costs developed through the use of the Class II/III simplified costing procedure.

The Class II/III standard costing procedure is set forth in paragraphs (n)(4)(i) through (n)(4)(xiv) of this section.

(i) The Class II or Class III railroad shall first determine which URCS regional application will be used based on its geographical location. The railroad's total estimated system variable expenses are calculated by multiplying its total operating expenses by the ratio of variable expenses to total expenses; this ratio is located in Worktable D8, Part 6, line 615, column 1 of the URCS printout for the appropriate region. If a railroad has passenger and freight service, the freight portion of the total estimated system variable expenses shall be calculated by multiplying the total estimated system variable expenses, calculated as above, by the ratio of freight related operating expenses to total railway operating expenses.

(ii) The total number of revenue carload terminal handlings, as determined from the railroad's records, shall be calculated as the sum of:

(A) Originated and terminated (local) revenue carloads multiplied by 2; plus

(B) Interchanged and either originated or terminated (interline) revenue carloads.

(iii) The total number of revenue carload interchange handlings, as determined from the railroad's records, shall be calculated as the sum of:

(A) Bridge (interchange to interchange) revenue carloads multiplied by 2; plus

(B) Revenue carloads that are interchanged and either originated or terminated (interline).

(iv) The system average shipment weight per car, as determined from the railroad's records, shall be calculated by dividing:

(A) Ton-miles-revenue freight by

(B) Loaded freight car miles.

(v) The system average loaded car miles per car, as determined from the railroad's records, shall be calculated by dividing:

(A) Revenue ton-miles by

(B) Revenue tons.

(vi) The railroad shall complete an URCS Phase III "Movement Costing Program" based on the application of URCS data for the appropriate region. The following data shall be inputs to the Phase III program application.

(A) The carrier code, either "REG 4" or "REG 7", shall correspond to the appropriate region.

(B) The type of shipment shall be designated as "OD" in order for the movement to be costed as an interline movement.

(C) The distance shall be the system average loaded car miles per car as developed in paragraph (n)(4)(v) of this section.

(D) The type of freight car shall be identified as a Box, General Service Equipped, which has an input user code of "3". If all of the traffic on the branch line is transported in a single type of car, and it is not a Box, General Service Equipped, the code for that type of car may be substituted.

(E) The number of freight cars shall be "1".

(F) The car ownership factor shall be designated as "R" for railroad owned cars unless all of the branch line traffic is moved in privately owned cars, in which case the code "P" for privately owned cars would be the input.

(G) The program requires a loss and damage input. The code "48", representing the average of all commodities, shall be used.

(H) The input for shipment weight shall be the system average shipment weight per car developed in paragraph (n)(4)(iv) of this section.

(I) The input for type of movement shall be "1", representing an individual car movement.

(vii) The ratios employed to separate the total estimated system variable expenses, as determined in paragraph (n)(4)(i) of this section, among terminal, interchange, and line-haul operations shall be based on the procedures outlined in this paragraph (n)(4)(vii). This separation shall reflect the variable costs resulting from the application of the URCS Phase III program based on the input factors specified in paragraph (n)(4)(vi) of this section. The ratios shall be calculated in the following manner:

(A) The terminal expenses calculated by the application of the Phase III program shall consist of the following:

(1) "Carload and Clerical Costs" shall be calculated as the sum of lines 256, 258, 260, 262, 264, 266, and 268.

(2) Switching expenses based on "Total SEM-Industry" shall be calculated by multiplying:

(i) The sum of lines 315, 317, and 319, by

(ii) Line 311.

(3) Car mile yard cost "CM(Y)-Industry" shall be calculated by multiplying:

(i) The sum of lines 426, 428, and 430, by

(ii) Line 422.

(3) Car day yard cost "CD(Y)-Industry" and "CD(Y)-L&UL" shall be calculated by multiplying:

(i) The sum of lines 452, 454, and 456, by

(ii) The sum of lines of 446 and 450.

(5) The expenses for accessorial services for railroad owned cars shall be calculated as the sum of:

(i) The product of line 422 and the sum of lines 464, 466, and 468; plus

(ii) The product of the sum of lines 446 and 450 and the sum of lines 476, 478, and 480.

(B) The interchange expenses calculated by the application of the Phase III program shall consist of the following:

(1) Switching expenses based on "Total SEM-Interchange" shall be calculated by multiplying

(i) The sum of lines 315, 317, and 319, by

(ii) Line 312.

(3) Car mile cost in interchange "CM(Y)-Interchange" shall be calculated by multiplying

(i) The sum of lines 426, 428, and 430, by

(ii) Line 423.

(4) Car day cost in interchange "CD(Y)-Interchange (L&E)" shall be calculated by multiplying

(i) The sum of lines 452, 454, and 456, by

(ii) Line 447.

(4) The expenses for accessorial services for railroad owned cars shall be calculated as the sum of:

(i) The product of line 423 and the sum of lines 464, 466, and 468; plus

(ii) The product of line 447 and the sum of lines 476, 478, and 480.

(C) The line-haul expenses resulting from the application of the Phase III program shall be calculated by subtracting the sum of:

(1) The terminal expenses as determined in paragraph (n)(4)(vii)(A) of this section, and

(2) The interchange expenses as determined in paragraph (n)(4)(vii)(B) of this section, from

(3) The total variable cost excluding loss and damage as calculated in the Phase III program at line 696.

(D) The ratio for terminal expenses shall be calculated by dividing the terminal expenses as determined in paragraph (n)(4)(vii)(A) of this section by the total variable cost excluding loss and damage as calculated in the Phase III program at line 696.

(E) The ratio for interchange expenses shall be calculated by dividing the interchange expenses as determined in paragraph (n)(4)(vii)(B) of this section by the total variable cost excluding loss and damage as calculated in the Phase III program at line 696.

(F) The ratio for line-haul expenses shall be calculated by dividing the line-haul expenses as determined in paragraph (n)(4)(vii)(C) of this section by the total variable cost excluding loss and damage as calculated in the Phase III program at line 696.

(viii) The railroad's total estimated system variable expenses shall be separated as follows:

(A) The total terminal variable expenses shall be calculated by multiplying the total estimated system variable expenses as determined in paragraph (n)(4)(i) of this section by the ratio for terminal expenses as determined in paragraph (n)(4)(vii)(D) of this section.

(B) The total interchange variable expenses shall be calculated by multiplying the total estimated system variable expenses as determined in paragraph (n)(4)(i) of this section by the ratio for interchange expenses as determined in paragraph (n)(4)(vii)(E) of this section.

(C) The total line-haul variable expenses shall be calculated by multiplying the total estimated system variable expenses as determined in paragraph (n)(4)(i) of this section by the ratio for line-haul expenses as determined in paragraph (n)(4)(vii)(F) of this section.

(ix) The railroad's unit costs shall be determined for terminal, interchange, and line-haul operations as follows:

(A) The terminal cost per carload shall be calculated by dividing the total terminal variable expenses as determined in paragraph (n)(4)(viii)(A) of this section by the total number of revenue carload terminal handlings as determined in paragraph (n)(4)(ii) of this section.

(B) The interchange cost per carload shall be calculated by dividing the total interchange variable expenses as determined in paragraph (n)(4)(viii)(B) of this section by the total number of revenue carload interchange handlings as determined in paragraph (n)(4)(iii) of this section.

(C) The line-haul cost per car mile shall be calculated by dividing the total line-haul variable expenses as determined in paragraph (n)(4)(viii)(C) of this section by the total system freight car miles, loaded and empty, as determined from the railroad's records.

(x) The modified terminal cost per carload is a composite of costs developed in the Phase III program and costs determined in accordance with paragraph (g) of this section and this paragraph. The modified terminal cost per carload shall be calculated for each type of car as follows:

(A) The station clerical cost per carload shall be developed in the following manner:

(1) The station clerical expense ratio shall be calculated by dividing the total clerical cost (the sum of lines 256, 258, 260, 262, 264, 266, and 268) by the terminal expenses as determined in paragraph (n)(4)(vii)(A) of this section.

(2) The station clerical cost per carload shall be calculated by multiplying the terminal cost per carload as determined in paragraph (n)(4)(ix)(A) of this section by the station clerical expense ratio.

(B) The interchange switching cost per carload shall be developed in the following manner:

(1) The total interchange switching expense shall be calculated by multiplying the sum of lines 315, 317, and 319 by line 312.

(2) The interchange switching ratio shall be calculated by dividing the total interchange switching expense by the interchange expenses as determined in paragraph (n)(4)(vii)(B) of this section.

(3) The interchange switching cost per carload shall be calculated by multiplying the interchange cost per carload as determined in paragraph (n)(4)(ix)(B) of this section by the interchange switching ratio.

(C) The freight car cost element shall be the freight car cost per car day for two days as developed for each car type in paragraph (g)(3) of this section.

(D) The modified terminal cost per carload shall be the total of the costs developed in paragraphs (n)(4)(x)(A), (n)(4)(x)(B), and (n)(4)(x)(C) of this section.

(xi) The terminal costs shall be calculated by multiplying the terminal cost per carload as determined in paragraph (n)(4)(ix)(A) of this section by the number of carloads that both:

(A) Originated or terminated on the branch, and

(B) Are local to the railroad serving the branch.

(xii) The interchange costs shall be calculated by multiplying the interchange cost per carload as determined in paragraph (n)(4)(ix)(B) of this section by the number of carloads that both:

(A) Originated or terminated on the branch, and

(B) Are received in or forwarded through interchange with other railroads.

(xiii) The line-haul costs shall be calculated by multiplying the line-haul cost per car mile as determined in paragraph (n)(4)(ix)(C) of this section by the total loaded and empty car miles generated on the railroad's system off the branch by cars that originated or terminated on the branch.

(xiv) The modified terminal costs shall be calculated by multiplying the modified terminal cost per carload as determined in paragraph (n)(4)(x)(D) of this section by the number of carloads that originated or terminated on the branch.

* * * * *

[FR Doc. 91-28867 Filed 12-2-91; 8:45 am]

BILLING CODE 7035-01-M

Proposed Rules

Federal Register
Vol. 56, No. 232
Tuesday, December 3, 1991

This section of the FEDERAL REGISTER contains notices to the public of the proposed issuance of rules and regulations. The purpose of these notices is to give interested persons an opportunity to participate in the rule making prior to the adoption of the final rules.

SECURITIES AND EXCHANGE COMMISSION

17 CFR Parts 240 and 249

[Release No. 34-29989; International Series Release No. 346; File No. S7-24-91]

RIN 3235-AE42

Large Trade Reporting System

AGENCY: Securities and Exchange Commission.

ACTION: Extension of time for comment.

SUMMARY: The Securities and Exchange Commission is extending the date by which comments must be submitted on the Large Trader Reporting System; Securities Exchange Act Release No. 29593 (August 22, 1991), 56 FR 42550 (August 28, 1991), from November 26, 1991 to January 6, 1992. The Commission has received a request to extend the comment period and believes that an extension of time is appropriate in light of the wide range of complex issues presented by the proposed Large Trader Reporting System.

DATES: Comments must be received on or before January 6, 1992.

ADDRESSES: Comments should be submitted in triplicate to Jonathan G. Katz, Secretary, Securities and Exchange Commission, 450 Fifth Street, NW., Stop 6-9, Washington, DC 20549. All comments received will be available for public inspection and copying in the Commission's Public Reference Room, 450 Fifth Street, NW., Washington, DC 20549.

FOR FURTHER INFORMATION CONTACT: Nicholas T. Chapekis, Special Counsel, (202) 272-3115, Division of Market Regulation, 450 Fifth Street, NW., Washington, DC 20549.

SUPPLEMENTARY INFORMATION: In Securities Exchange Act Release No. 29593, the Commission proposed for comment Rule 13h-1, which combined with proposed Form 13H would establish the Large Trader Reporting System. As a result of the wide range of complex issues presented in the release, the representatives of several domestic and foreign market participants have requested an extension of the comment period. The Commission believes that an extension of time is appropriate and would afford commentators the opportunity to prepare more insightful comments. Therefore, the Commission is extending the comment period for Securities Exchange Act Release No. 29593 from November 26, 1991 to January 6, 1992.

Dated: November 26, 1991.

By the Commission.

Margaret H. McFarland,
Deputy Secretary.

[FR Doc. 91-28931 Filed 12-2-91; 8:45 am]

BILLING CODE 8010-01-M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Parts 5, 20, 100, 101, 105, and 130

Industry and Small Business Participation; Consumer and Health Professionals Participation; Notice of Meetings on Proposed Rules To Amend the Food Labeling Regulations

AGENCY: Food and Drug Administration, HHS.

ACTION: Meeting on proposed rules.

SUMMARY: The Food and Drug Administration (FDA) announces two forthcoming meetings on the proposed rules to implement the Nutrition Labeling and Education Act of 1990 (the NLEA). The first meeting is for industry and small business, and the second meeting is for consumer and health professionals.

DATES: The meeting for industry and small business will be held on Thursday, December 12, 1991, 8:30 a.m. to 12 m. The meeting for consumer and health professionals will be held on Thursday, December 12, 1991, 1 p.m. to 4:30 p.m.

ADDRESSES: The meeting will be held in Salon 4, Crystal Gateway Marriott, 1700 Jefferson Davis Hwy., Arlington, VA 22202.

FOR FURTHER INFORMATION CONTACT:
Industry and small business should contact: Nathaniel L. Geary, Food and Drug Administration, 5600 Fishers Lane, Rockville, MD 20857, 301-443-6776, 301-443-5153 (FAX).
Consumers should contact: Martha Waugh, Food and Drug Administration, Office of Consumer Affairs, 5600 Fishers Lane, Rockville, MD 20857, 301-443-5006, 301-443-9767 (FAX).
Health professionals should contact: Betty Palsgrove, Food and Drug Administration, Office of Health Affairs, 5600 Fishers Lane, Rockville, MD 20857, 301-443-5470, 301-443-2446 (FAX).

SUPPLEMENTARY INFORMATION: FDA, Center for Food Safety and Applied Nutrition, Office of Consumer Affairs, Office of Health Affairs, and the Office of Small Business, Scientific, and Trade Affairs, announce two forthcoming meetings for: (1) Consumers and health professionals and (2) industry and small business. The purpose of these meetings is to brief manufacturers, repackers, distributors, and retailers of consumer food products, and consumers and health professionals on the NLEA (Pub. L. 101-535) and to encourage future comments on the proposed rules for implementing the NLEA which were published in the **Federal Register** of November 27, 1991 (56 FR 60366 through 60878). Preregistration is required because space is limited.

Dated: November 25, 1991.

Michael R. Taylor,
Deputy Commissioner for Policy.

[FR Doc. 91-28983 Filed 12-2-91;8:45am]

BILLING CODE 4160-01-M

DEPARTMENT OF THE TREASURY

Internal Revenue Service

26 CFR Part 1

[EE-46-91]

RIN 1545-AP74

Taxation of Fringe Benefits and Exclusion from Gross Income of Certain Fringe Benefits; Hearing

AGENCY: Internal Revenue Service, Treasury.

ACTION: Notice of public hearing on proposed regulations.

SUMMARY: This document provides notice of a public hearing on proposed

Income Tax Regulations that contain proposed amendments relating to whether certain benefits qualify as working condition fringes and, therefore, are excludable from the recipient's gross income under section 132(a)(3) of the Internal Revenue Code.

DATES: The public hearing will be held on Thursday, January 30, 1992, beginning at 10 a.m. Requests to speak and outlines of oral comments must be received by Thursday, January 16, 1992.

ADDRESSES: The public hearing will be held in the IRS Auditorium, Seventh Floor, 7400 Corridor, Internal Revenue Building, 1111 Constitution Avenue, NW., Washington, DC. Requests to speak and outlines of oral comments should be submitted to the Internal Revenue Service, P.O. Box 7604, Ben Franklin Station, Attn: CC:CORP:T:R (EE-46-91), room 5228, Washington, DC 20044.

FOR FURTHER INFORMATION CONTACT: Bob Boyer of the Regulations Unit, Assistant Chief Counsel (Corporate), 202-377-9231, (not a toll-free number).

SUPPLEMENTARY INFORMATION: The subject of the public hearing is regulations proposing amendments to the Income Tax Regulations (26 CFR part 1) under section 132 of the Internal Revenue Code of 1986. The amendments pertain to bona fide volunteers who perform services for exempt organizations or for a Federal, state, or local governmental unit and to government employees who are provided transportation because of bona fide business-oriented security concerns. These regulations appeared in the proposed rules section of the **Federal Register** for September 25, 1991, (56 FR 48465).

The rules of § 601.601 (a)(3) of the "Statement of Procedural Rules" (26 CFR part 601) shall apply with respect to the public hearing. Persons who have submitted written comments within the time prescribed in the notice of proposed rulemaking and who also desire to present oral comments at the hearing on the proposed regulations should submit not later than Thursday, January 16, 1992, an outline of the oral comments/testimony to be presented at the hearing and the time they wish to devote to each subject.

Each speaker (or group of speakers representing a single entity) will be limited to 10 minutes for an oral presentation exclusive of the time consumed by the questions from the panel for the government and answers to these questions.

Because of controlled access restrictions, attendees cannot be admitted beyond the lobby of the Internal Revenue Building until 9:45 a.m.

An agenda showing the scheduling of the speakers will be made after outlines are received from the persons testifying. Copies of the agenda will be available free of charge at the hearing.

By direction of the Commissioner of Internal Revenue.

Cynthia E. Grigsby,

Alternate Federal Register Liaison Officer, Assistant Chief Counsel (Corporate).

[FR Doc. 91-28860 Filed 12-2-91; 8:45 am]

BILLING CODE 4830-01-M

DEPARTMENT OF TRANSPORTATION

National Highway Traffic Safety Administration

49 CFR Parts 567 and 568

[Docket No. 91-62; Notice 1]

RIN 2127-AE27

Certification of Multistage Vehicles

AGENCY: National Highway Traffic Safety Administration (NHTSA); DOT.

ACTION: Notice of proposed rulemaking.

SUMMARY: This notice proposes to amend the certification requirement that apply to incomplete vehicles other than chassis-cabs. Incomplete vehicles are vehicles that include at least a frame and chassis structure, power train, steering system, suspension system, and braking system, but need further manufacturing performed on them to become completed vehicles. Incomplete vehicle manufacturers have long been required to provide a document with every incomplete vehicle that establishes guidelines for completing the vehicle. If the guidelines are followed by the manufacturer that completes the vehicle, the completed vehicles will conform with applicable safety standards. For those incomplete vehicles that are chassis-cabs, i.e., incomplete vehicles with completed occupant compartments, the incomplete vehicle manufacturer is currently required to provide the guideline document and affix a certification label to the incomplete vehicle. On this certification label, the chassis-cab manufacturer is required to make the same types of statements about the conditions under which the completed vehicle will comply with the safety standards as are set forth in the complete vehicle document. The final stage manufacturer is then permitted to "pass through" the certification, i.e., rely on the certification made by the chassis-cab manufacturer.

NHTSA is proposing to extend the certification labeling requirements that currently apply to chassis-cab incomplete vehicles to all incomplete vehicles. This proposal responds to a court decision holding than an extension of one of the Federal motor vehicle safety standards was not practicable as it related to multistage vehicles for which the final stage manufacturer cannot pass through the certification of the incomplete vehicle manufacturer. A final rule adopting this proposal would eliminate the concerns expressed by the court in this regard by permitting pass-through certifications for all types of multistage vehicles.

DATES: Comments on this notice must be received by NHTSA not later than January 31, 1992. If adopted in a final rule, these proposed amendments would take effect 180 days after the date of publication of the final rule.

ADDRESSES; Comments should refer to the docket and notice number set forth in the heading of this notice and be submitted to: NHTSA Docket Section, room 5109, 400 Seventh Street, SW., Washington, DC 20590. Docket hours are 9:30 a.m. to 4 p.m. Monday through Friday.

FOR FURTHER INFORMATION CONTACT: Mr. Clarke B. Harper, Office of Vehicle Safety Standards, room 5320, 400 Seventh Street, SW., Washington, DC 20590. Mr. Harper can be reached by telephone at (202) 366-2264.

SUPPLEMENTARY INFORMATION: Section 114 of the National Traffic and Motor Vehicle Safety Act of 1966 (15 U.S.C. 1403) requires every manufacturer of motor vehicles to certify that each of its vehicles conforms to all applicable Federal motor vehicle safety standards. This statutory certification requirement is straightforward with respect to vehicles produced by a single manufacturer. In such cases, the manufacturer is simply being asked to assume responsibility for its vehicles.

However, application of the statutory certification requirement is more complex for multi-stage vehicles, i.e., vehicles produced in two or more stages. These vehicles are not produced by a single manufacturer on an assembly line as is the typical passenger car. Instead, one manufacturer produces an "incomplete vehicle" which requires further manufacturing operations to become a completed vehicle. As defined in 49 CFR 568.3, an incomplete vehicle at a minimum includes a frame and chassis structure, power train, steering system, suspension system, and braking system. The spectrum of incomplete vehicles ranges, in terms of degree of

incompleteness, from "stripped chassis," which consist of only those minimum features to "chassis-cabs". Chassis-cabs are incomplete vehicles with fully completed occupant compartments that require only the addition of cargo-carrying, work-performing, or load-bearing components to perform their intended functions and become completed vehicles. *See* 49 CFR 567.3.

Most incomplete vehicles are manufactured by large manufacturers, such as Chrysler, Ford, and General Motors. The incomplete vehicles are then supplied to intermediate and final stage manufacturers. These subsequent manufacturers perform the manufacturing operations needed to make an incomplete vehicle into a completed vehicle. Intermediate and final stage manufacturers are generally small businesses. Vehicles manufactured in two or more stages are generally customized vehicles, the demand for which is too small to justify a large manufacturer devoting its resources to produce the vehicles in completed form entirely at its manufacturing facilities.

Throughout the rest of this preamble, the discussion assumes that any multi-stage vehicle is one manufactured in only two stages, i.e., there is an incomplete vehicle manufacturer and a final stage manufacturer. This limitation is intended to avoid needless complexity. For informational purposes, the agency notes that the manufacture of vehicles in three or more stages is more complex in that one or more intermediate manufacturers are involved. The incomplete vehicle manufacturer must provide the intermediate manufacturer with the same information and representations required to be provided to final stage manufacturers. The intermediate manufacturer must, in turn, furnish the incomplete vehicle manufacturer's information and representations to the final stage manufacturer or any subsequent intermediate manufacturers, along with an addendum showing all changes that should be made to the document to reflect the intermediate manufacturer's work on the vehicle.

The issue of which manufacturer must certify the compliance of vehicles manufactured in two or more stages poses difficulties not presented by the certification of vehicles produced by a single manufacturer. On the one hand, the incomplete vehicle manufacturer is usually a large manufacturer with substantial engineering and financial resources. Moreover, the design of the incomplete vehicle substantially affects the ability of the completed vehicle to comply with many of the safety standards. For instance, chassis-cabs come with completed occupant compartments. The controls and displays installed in the chassis-cab will substantially determine whether the completed vehicle complies with Standard No. 101, *Controls and Displays*, the seats in the chassis-cab will substantially determine whether the completed vehicle complies with Standard No. 207, *Seating Systems*, and so forth. It would not be appropriate to require the final stage manufacturer alone to certify that the completed chassis-cab complies with all applicable safety standards, because the final stage manufacturer would then, in essence, be certifying the work performed by the chassis-cab manufacturer, over which the final stage manufacturer had no control and about which it would have no direct knowledge.

On the other hand, it would also be inappropriate to require the incomplete vehicle manufacturer to certify that a completed vehicle will comply with all applicable safety standards irrespective of what the final stage manufacturer does to complete the vehicle. For instance, a stripped chassis does not have any controls and displays or any seats. The manufacturer that produced the stripped chassis cannot know whether the completed vehicle will comply with Standards Nos. 101 and 207, because compliance with those standards will be determined entirely by the controls and displays and seats installed in the completed vehicle by the final stage manufacturer.

To address this situation, since 1971, NHTSA has required incomplete vehicle manufacturers to furnish certain information with each incomplete vehicle. With reference to each safety standard, 49 CFR 568.4(a)(7) requires the incomplete vehicle manufacturer to make one of three alternative statements for every incomplete vehicle it sells. The three alternative statements are:

1. The incomplete vehicle manufacturer may state that the completed vehicle will conform to a particular standard if no alterations are made to identified components of the incomplete vehicle. For instance, if the incomplete vehicle is a chassis-cab equipped with seats, the incomplete vehicle manufacturer may state that the vehicle completed from this chassis-cab will conform to Standard No. 207 as long as the seats installed in the chassis-cab are not altered in any way. In this instance, a final stage manufacturer that did not alter the seats in the incomplete vehicle could base its certification of compliance with Standard No. 207 entirely upon the statement by the incomplete vehicle manufacturer and the fact that it had made no such alterations.

2. At the other extreme, the incomplete vehicle manufacturer may state that conformity with the standard is "not substantially affected" by the design of the incomplete vehicle, and that the incomplete vehicle manufacturer makes no representation as to conformity with the standard. For instance, if the incomplete vehicle is a stripped chassis without any controls and displays, it is obvious that the completed vehicle's conformity with Standard No. 101 is totally determined by the controls and displays put in the completed vehicle by the final stage manufacturer. In this instance, the incomplete vehicle manufacturer may state that conformity with Standard No. 101 is not substantially affected by the design of the stripped chassis, and that the incomplete vehicle manufacturer makes no representation as to conformity with Standard No. 101. Since conformity with Standard No. 101 is entirely within the control of the final stage manufacturer in this instance, the final stage manufacturer's certification of conformity with Standard No. 101 would be based upon the final stage manufacturer's own knowledge and actions.

It is important to note that this statement includes a factual element, i.e., that the conformity of the completed vehicle is not substantially affected by the design of the incomplete vehicle. The manufacturer of a stripped chassis may not make this statement with respect to a standard, such as a braking standard, if the design of the braking system installed on the stripped chassis is in fact an important determinant of compliance with the safety standard.

3. Between these two extremes lies the majority of situations. The incomplete vehicle manufacturer may state that the completed vehicle will conform to a particular standard if the vehicle is completed within certain specified conditions. For instance, the incomplete vehicle manufacturer may state that a vehicle completed from its incomplete vehicle will conform to the requirements of Standard No. 105, *Hydraulic Brake Systems*, as long as the completed vehicle does not exceed any of the gross axle weight ratings assigned by the incomplete vehicle manufacturer, the center of gravity at the assigned gross vehicle weight rating is not higher than a specified height, and the brake system installed on the incomplete vehicle is not altered in any way. In

such a case, a final stage manufacturer that completes the vehicle in accordance with the instructions that accompanied the incomplete vehicle could base its certification of compliance with Standard No. 105 entirely upon the statement by the incomplete vehicle manufacturer.

The agency determined that this approach was fair and reasonable for both incomplete vehicle manufacturers and final stage manufacturers. With respect to the incomplete vehicle manufacturers, those manufacturers were required, at the very least, to provide instructions about how to complete the vehicle so that it would comply with each standard, if the design of the incomplete vehicle substantially affected the completed vehicle's conformity with the standard in question. It is undeniably a burden to require incomplete vehicle manufacturers to devote the time and resources needed to develop information about how a vehicle can be completed so that it will conform to the safety standards. However, this burden must be borne by some manufacturer to enable the vehicle to be certified in accordance with the Safety Act. As between the incomplete vehicle manufacturer and the final stage manufacturer, the incomplete vehicle manufacturer is burdened proportionally to a far lesser extent under this approach than the final stage manufacturer, because of the incomplete vehicle manufacturer's vastly greater financial and engineering resources.

On the other hand, it is not appropriate to so burden the incomplete vehicle manufacturer with respect to those safety standards with which compliance is not substantially affected by the design of the incomplete vehicle. As noted above, a stripped chassis has no controls and displays. Hence, whether the completed vehicle complies with Standard No. 101 is entirely dependent upon the actions of the final stage manufacturer and is outside the control of the incomplete vehicle manufacturer. Hence, the incomplete vehicle manufacturer is not required to provide a means of certifying compliance for those standards with which compliance is not substantially affected by the design of the incomplete vehicle. However, the incomplete vehicle manufacturer must specifically identify all of the standards in this category, in order to alert the final stage manufacturer to both the existence of these standards and the fact that the final stage manufacturer is independently responsible for certifying compliance with them. Thus, final stage manufacturers are alerted that they cannot produce complete vehicles from these incomplete vehicles unless they can independently certify compliance with each safety standard as to which the incomplete vehicle manufacturer makes no representation.

Final stage manufacturers are also alerted that they can complete the incomplete vehicle outside of the incomplete vehicle manufacturer's instructions, thus potentially jeopardizing the vehicle's compliance with applicable safety standards, only if they independently certify compliance with those standards. Those final stage manufacturers that have the financial and engineering resources to certify compliance with standards while going outside the incomplete vehicle manufacturer's instructions have the flexibility to do so. Those final stage manufacturers that lack the financial and engineering resources to make such a certification based on their own knowledge may certify compliance without incurring any testing or other burdens. All that is required in that case is that the final stage manufacturer complete the vehicle in accordance with the incomplete vehicle manufacturer's instructions. The agency believed that this framework appropriately apportioned the certification burden between incomplete vehicle manufacturers and final stage manufacturers.

This certification scheme was challenged in 1973 in a lawsuit filed by a company that mounted cement mixers on chassis-cabs. That company alleged that the multistage certification scheme promulgated by NHTSA was invalid as it applied to companies like itself, because the final state manufacturer was required to make the sole certification of compliance for the entire vehicle. The United States Court of Appeals for the Seventh Circuit held that "to the extent that the regulations require [the final stage manufacturer] to make the sole certification of compliance of the entire vehicle * * *, they must be declared invalid." *Rex Chainbelt, Inc.* v. *Volpe,* 486 F.2d 757, 762 (7th Cir. 1973). Similarly, in a subsequent appeal, the court interpreted this holding to mean that the Safety Act "requires that in instances where the customer purchases a chassis-cab from its manufacturer and thereafter the mixer from the mixer manufacturer, the 'entire vehicle' must be certified via two certifications, with the chassis-cab manufacturer certifying its chassis-cab, and with the [final stage] manufacturer certifying its mixer and the effect of the mounting, if any, to thus obtain effective certification of the 'entire vehicle.' " *Rex Chainbelt, Inc.* v. *Brinegar,* 511 F.2d 1215, 1216 (7th Cir. 1975).

In response to this court decision, NHTSA amended its certification regulation (49 CFR part 567) to require the manufacturer of those incomplete vehicles categorized as chassis-cabs to affix a certification label to its chassis-cabs. 42 FR 37814; July 25, 1977. The chassis-cab manufacturer was required to make the same type of statement on the certification label that it had long been required to make in the incomplete vehicle document. Specifically, 49 CFR 567.5(a) requires the chassis-cab manufacturer to include on its certification label one of the following three statements for each applicable standard:

1. The chassis-cab conforms to the standard;

2. The chassis-cab will conform to the standard if it is completed in accordance with the instructions furnished in the incomplete vehicle document; or

3. Conformity with the standard is not substantially affected by the design of the chassis-cab.

From the perspective of the chassis-cab manufacture, the effect of this amendment was to require chassis-cab manufacturers to furnish this information in two places—the incomplete vehicle document and a certification label affixed to the chassis cab—instead of only in the incomplete vehicle document, as had been the case before the amendment. This amendment did not require the chassis-cab manufacturer to do anything more or different in substance than it had done previously to provide the information in the incomplete vehicle document.

From the perspective of a final stage manufacturer that uses a chassis-cab in producing a complete vehicle, this amendment created the possibility of a "pass through certification." "Pass through certification" refers to instances in which the chassis-cab manufacturer has made either statement 1 or statement 2 above, and the final stage manufacturer either has not affected the previously-certified compliance, or has completed the vehicle in accordance with the chassis-cab manufacturer's instructions. In such cases, 49 CFR 567.5(c)(7) permits the final stage manufacturer simply to state on its certification label that it has not affected the previously certified conformity of the chassis-cab or that it has followed the chassis-cab manufacturer's instructions for completing the vehicle, instead of providing its own certification that the

vehicle actually conforms to the standard at issue.

The 1977 amendments were limited to chassis-cabs, because the judgment in *Rex Chainbelt* was limited to chassis-cabs. However, a November 28, 1990 decision by the United States Court of Appeals for the Sixth Circuit, in *National Truck Equipment Association* v. *National Highway Traffic Safety Administration*, 919 F.2d 1148 (6th Cir. 1990) has caused the agency to reexamine Standard No. 204, *Steering Control Rearward Displacement* (49 CFR 571.204), to cover some additional light trucks were not practicable as they related to multistage vehicles for which the final stage manufacturer cannot pass through a certification by the incomplete vehicle manufacturer. After noting that NHTSA's regulations do not permit final stage manufacturers that use incomplete vehicles other than chassis-cabs to pass through a certification made by the incomplete vehicle manufacturer, the court observed that it could see no reason why the certification requirements for those incomplete vehicles that are chassis-cabs should differ from those for other incomplete vehicles.

NHTSA has tentatively determined that there is no substantive justification for this differing treatment. As noted above, the certification requirements for chassis-cabs are different from those applicable to other incomplete vehicles because the *Rex Chainbelt* decision addressed only chassis-cabs and mandated pass-through certification provisions only for chassis-cabs. Accordingly, this notice proposes to extend the pass-through certification requirements that currently apply to chassis-cabs to all incomplete vehicles.

The agency does not believe this proposed extension of the pass-through certification requirements would impose any additional burdens on incomplete vehicle manufacturers. Incomplete vehicle manufacturers have long been required by 49 CFR 568.4(a)(7) to issue an incomplete vehicle document that includes one of the following three statements for *every* incomplete vehicle and for *every* applicable standard:

1. "the vehicle when completed *will conform to the standard* if no alterations are made in identified components of the incomplete vehicles;" (49 CFR 568.4(a)(7)(i))

2. "a statement of specific conditions of final manufacture under which the manufacturer specifies that the completed vehicle *will conform to the standard;*" (49 CFR 568.4(a)(7)(ii)) or

3. "*conformity with the standard* is not substantially affected by the design of the incomplete vehicle." (49 CFR 568.4(a)(7)(iii)) (Emphases added).

The emphasized language shows that manufacturers of incomplete vehicles other than chassis-cabs have long been required to make representations as to the completed vehicle's conformity with all applicable standards. If an incomplete vehicle manufacturer were to make a false statement in its incomplete vehicle document, the incomplete vehicle manufacturer would not have complied with part 568, which noncompliance would violate section 108(a)(1)(E) of the Safety Act (15 U.S.C. 1397(a)(1)(E)), and would make the incomplete vehicle manufacturer liable for civil penalties under section 109 of the Safety Act (15 U.S.C. 1398). For instance, an incomplete vehicle manufacturer would violate part 568 if it were to state, pursuant to 568.4(a)(7)(ii), that a vehicle completed within specified guidelines will conform with a standard, when that is not the case. Such a misstatement could also have significant product liability implications. Thus, the agency believes that incomplete vehicle manufacturers have long been required for both legal and practical reasons, to assure the accuracy of the instructions they provide for completing all of their incomplete vehicles.

Accordingly, the agency does not believe this proposal will require incomplete vehicle manufacturers to "tighten up" their instructions in any way. NHTSA believes this proposal would only require incomplete vehicle manufacturers to take the statements currently required to be provided in the incomplete vehicle document, pursuant to part 568, and affix substantively identical statements to a certification label on the incomplete vehicle. This would not require any additional testing, analysis, or evaluations beyond what the incomplete vehicle manufacturer must do now to support the statements in the incomplete vehicle document. If any commenter believes that incomplete vehicle manufacturers will "tighten up" their instructions from those that are currently provided pursuant to part 568, the commenter is asked to specifically identify the basis for such an assertion.

In proposing that the current chassis-cab certification requirements be extended to all incomplete vehicles, the agency is making one minor modification for incomplete vehicles other than chassis-cabs. The chassis-cabs certification labeling requirements specify that the certification label for chassis-cabs shall be located in the same place as the certification labels are located in single stage vehicles, such as the door-latch post, hinge pillar, instrument panel, and so forth. See 49 CFR 567.4(c). However, incomplete vehicles other than chassis-cabs may not have these locations.

NHTSA proposes to address this potential difficulty by permitting the incomplete vehicle manufacturer to furnish its certification label along with the incomplete vehicle document, instead of trying to attach it to some part of the incomplete vehicle. The final stage manufacturer would then affix the incomplete vehicle manufacturer's certification label, as well as its own certification label, at the specific locations on the completed vehicle. This would ensure that both certification labels are readily accessible on the completed vehicle without imposing a significant additional burden on either manufacturer. The public is invited to comment on this proposal and to offer alternative means of addressing this potential difficulty.

Rulemaking Analysis and Notices

Executive Order 12291 (Federal Regulation) and DOT Regulatory Policies and Procedures

NHTSA has considered the impacts of this proposed rulemaking action and determined that it is neither major within the meaning of Executive Order 12291 nor significant within the meaning of the Department of Transportation's regulatory policies and procedures. As explained in detail above, the agency believes that the amendments proposed in this notice would not impose any significant costs or burdens on incomplete vehicle manufacturers and could provide a benefit to those final stage manufacturers that complete vehicles in accordance with the incomplete vehicle document. The agency has prepared a preliminary regulatory evaluation (PRE) of the estimated impacts. That PRE is available in the docket for this rulemaking action.

Regulatory Flexibility Act

NHTSA has also considered the impacts of this proposed rule under the Regulatory Flexibility Act. NHTSA believes this proposal could have a beneficial impact on final state manufacturers, most of whom are small businesses. However, as explained in detail in this preamble, the agency is seeking information to help it determine whether the beneficial impact on these small businesses would be significant. A discussion of the small business aspects of this proposal is included in the PRE for this rulemaking. Interested persons are invited to consult that PRE.

National Environmental Policy Act

NHTSA has also analyzed this proposed action for the purposes of the National Environmental Policy Act, and determined that, if it is adopted in a final rule, it would not have a significant impact on the quality of the human environment.

Executive Order 12612 (Federalism)

This proposal has also been analyzed in accordance with the principles and criteria contained in Executive Order 12612, and NHTSA has determined that it does not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

List of Subjects in 49 CFR Parts 567 and 568

Labeling, Motor vehicle safety, Motor vehicles, Reporting and record keeping requirements.

In consideration of the foregoing, NHTSA proposes to amend 49 CFR parts 567 and 568 as follows:

PART 567—[AMENDED]

1. The authority citation for part 567 would continue to read as follows:

Authority 15 U.S.C. 1392, 1397, 1401, 1403, and 1407; 15 U.S.C. 1912 and 1915; 15 U.S.C. 2021, 2022, and 2026; delegation of authority at 49 CFR 1.50.

2. Section 567.3 would be amended by removing the definition of "chassis-cab" and adding in its place a definition of "incomplete vehicle," to read as follows:

§ 567.3 Definitions.

* * * * *

Incomplete vehicle means an assembalge consisting, as a minimum, of frame and chassis structure, power train, steering system, suspension system, and braking system, to the extent that those systems are to be part of the complete vehicle, that requires further manufacturing operations, other than the addition of readily attachable components, such as mirrors or tire and rim assemblies, or minor finishing operations, such as painting, to become a complete vehicle.

* * * * *

3. Section 567.5 would be revised to read as follows:

§ 567.5 Requirements for manufacturers of vehicles manufactured in two or more stages.

(a) Except as provided in paragraph (e) of this section, each manufacturer of an incomplete vehicle shall, for every incomplete vehicle, either affix a label, in the location and form specified in § 567.4 or provide such a label along with the incomplete vehicle document specified in § 568.4. this label shall contain the statements specified in paragraph (a)(1) that are applicable to the incomplete vehicle and the information specified in paragraphs (a)(2) and (a)(3).

(1)(i) "This incomplete vehicle conforms to Federal Motor Vehicle Safety Standard Nos. ______." The statement shall be completed by inserting the numbers of the safety standards (e.g., 101, 207) to which the incomplete vehicle conforms.

(ii) "This vehicle will conform to Standard Nos. ______ if it is completed in accordance with the instructions contained in the incomplete vehicle document furnished pursuant to 49 CFR part 568." The statement shall be completed by inserting the numbers of the safety standards as to which conformity is substantially affected by both the design of the incomplete vehicle and the manner in which the vehicle is completed (i.e., the standards listed under category (ii) in § 568.4(a)(7) of this chapter).

(iii) "Conformity to the other safety standards applicable to this vehicle when completed is not substantially affected by the design of this incomplete vehicle."

(2) Name of the incomplete vehicle manufacturer preceded by the words "INCOMPLETE VEHICLE MANUFACTURED BY" or "INCOMPLETE VEHICLE MFD BY."

(3) Month and year of manufacture of the incomplete vehicle. This may be spelled out, as in "June 1990," or expressed in numerals, as in "6/90." No preface is required.

(b) Except as provided in paragraphs (e) and (f) of this section, for every incomplete vehicle for which an intermediate manufacturer is required by § 568.5 to furnish an addendum to the incomplete vehicle document specified in § 568.4, the intermediate manufacturer of a vehicle manufactured in two or more stages shall also either affix a label, in the location and form specified in § 567.4, or provide such a label along with the incomplete vehicle document and addendum. This label shall contain the statements specified in paragraph (b)(1) that are applicable to the incomplete vehicle and the information specified in paragraphs (b)(2) and (b)(3).

(1)(i) "With respect to Standard Nos. ______, the instructions of prior manufacturers have been followed so that those prior manufacturers now certify that this incomplete vehicle conforms to those standards." The statement shall be completed by inserting the numbers of all or less than all of the standards, but only those standards for which the latest prior certification was in the form prescribed in paragraphs (a)(1)(ii) or (b)(1)(iii) of this section.

(ii) "This incomplete vehicle conforms to Federal Motor Vehicle Safety Standard Nos. ______." The statement shall be completed by inserting the numbers of the other standards to which the incomplete vehicle conforms, but excluding those standards conformity to which has already been certified pursuant to paragraphs (a)(1)(i) or (b)(1)(i) of this section.

(iii) "This vehicle will conform to Standard Nos. ______ if it is completed in accordance with the amended incomplete vehicle document furnished pursuant to 49 CFR part 568." The statement shall be completed by inserting the numbers of the safety standards conformity to which is substantially affected by both the design of the incomplete vehicle (as modified by the intermediate manufacturer) and the manner in which the vehicle is completed.

(iv) "Conformity to Standard Nos. ______ is no longer substantially affected by the design of this incomplete vehicle." This statement shall be completed by inserting the numbers of all or less than all of the standards, but only those standards respecting which the latest prior certification was in the form prescribed in paragraphs (a)(1)(i) or (ii), or (b)(1)(i), (ii), or (iii) of this section.

(2) Name of the intermediate manufacturer preceded by the words "INTERMEDIATE MANUFACTURE BY" or "INTERMEDIATE MFR BY."

(3) Month and year in which the intermediate manufacturer performed its last manufacturing operation on the incomplete vehicle. This may be spelled out, as in "June 1990," or expressed in numerals, as in "6/90." No preface is required.

(c) Except as provided in paragraphs (e) and (f) of this section, each final stage manufacturer, as defined in § 568.3 of this chapter, of a vehicle manufactured in two or more stages shall affix to each vehicle it completes any labels provided with the incomplete vehicle document, pursuant to paragraphs (a) and (b) of this section, in the location specified in § 567.4. Each final stage manufacturer shall also affix to each vehicle it completes a label of the type and form and in the location specified in § 567.4. This label shall contain the information specified in paragraphs (c)(1) through (c)(6) of this section, and one of the statements specified in paragraph (c)(7) of this

section that applies to the completed vehicle.

(1) Name of the final stage manufacturer, preceded by the words "MANUFACTURED BY" or "MFD BY."

(2) Month and year in which final stage manufacture is completed. This may be spelled out, as in "JUNE 1990," or expressed in numerals, as in "6/90." No preface is required.

(3) "GROSS VEHICLE WEIGHT RATING" or "GVWR," followed by the appropriate value in pounds, which shall be not less than the sum of the unloaded vehicle weight, rated cargo load, and 150 pounds multiplied by the vehicle's designated seating capacity, for all vehicles other than school buses. For school buses, the gross vehicle weight rating shall be not less than the sum of the unloaded vehicle weight, rated cargo load, and 120 pounds multiplied by the vehicle's designated seating capacity.

(4) "GROSS AXLE WEIGHT RATING" or "GAWR," followed by the appropriate value in pounds for each axle, identified in order from front to rear (e.g., front, first intermediate, second intermediate, rear). The ratings for any consecutive axles having identical gross axle weight ratings when equipped with tires having the identical tire size designation may be stated as a single value, with the label indicating to which axles the ratings apply.

Examples of Combined Ratings

(i) GAWR: All axles—4080 with 7.00-15LT(D) tires

(ii) GAWR: Front—12,000 with 10.00-20(G) tires

First intermediate to rear—15,000 with 12.00-20(H) tires

(5) The vehicle identification number assigned to the vehicle by the incomplete vehicle manufacturer, pursuant to Standard No. 115 (49 CFR 571.115).

(6) The type classification of the completed vehicle, as specified in 571.3 of this chapter (e.g., truck, multipurpose passenger vehicle, bus, trailer).

(7) One of the following three certification statements. Statement (i) may be used only by final stage manufacturers meeting the requirements described in the instruction portion of that paragraph. Statements (ii) or (iii) may be used by any final stage manufacturer.

(i) "The final stage manufacturer has not affected this vehicle's conformity with those Federal Motor Vehicle Safety Standards with which the incomplete vehicle manufacturer or intermediate vehicle manufacturer has previously fully certified conformity. The vehicle has been completed in accordance with the prior manufacturer's instructions, where applicable. This vehicle conforms to all other applicable Federal Motor Vehicle Safety Standards in effect in (month, year)."

This certification statement may be used only in cases in which the final stage manufacturer has:

(A) Not affected conformity to any standards as to which compliance has been fully certified by an incomplete vehicle manufacturer, pursuant to paragraph (a)(1)(i) of this section, or by an intermediate manufacturer, pursuant to paragraphs (b)(1)(i) or (b)(1)(ii) of this section, and

(B) Completed the vehicle in accordance with a prior manufacturer's instructions for standards listed in a conditional certification statement by an incomplete vehicle manufacturer, pursuant to paragraph (a)(1)(ii) of this section, or by an intermediate manufacturer, pursuant to (b)(1)(iii) of this section.

The date shown in the third sentence of this certification statement shall be not earlier than the date of manufacture of the incomplete vehicle as shown on the incomplete vehicle manufacturer's label, pursuant to paragraph (a)(3) of this section, and not later than the date of completion of the final stage manufacture of the completed vehicle as shown on the final stage manufacturer's label, pursuant to paragraph (c)(2) of this section.

(ii) "Conformity of the incomplete vehicle to Federal Motor Vehicle Safety Standards Nos. ______ has not been affected by final stage manufacture. With respect to Standards Nos. ______, the vehicle has been completed in accordance with the prior manufacturer's instructions. This vehicle conforms to all other applicable Federal Motor Vehicle Safety Standards in effect in (month, year)."

The first sentence of this certification statement shall be completed by inserting the numbers of all or less than all of the standards, and only those standards, as to which an incomplete vehicle manufacturer or an intermediate manufacturer has fully certified compliance, pursuant to paragraph (a)(1)(i), (b)(1)(i), or (b)(1)(ii) of this section. The second sentence of this certification statement shall be completed by inserting the numbers of all or less than all of the standards, and only those standards, with respect to which the final stage manufacturer has completed the vehicle in accordance with a prior manufacturer's instructions for standards listed in a conditional certification statement by an incomplete vehicle manufacturer, pursuant to paragraph (a)(1)(ii) of this section, or by an intermediate manufacturer, pursuant to (b)(1)(iii) of this section. The date shown in the third sentence of this certification statement shall be not earlier than the date of manufacture of the incomplete vehicle as shown on the incomplete vehicle manufacturer's label, pursuant to paragraph (a)(3) of this section, and not later than the date of completion of the final stage manufacture of the completed vehicle as shown on the final stage manufacturer's label, pursuant to paragraph (c)(2) of this section.

(iii) "This vehicle conforms to all applicable Federal Motor Vehicle Safety Standards in effect in (month, year)."

The date shown in this certification statement shall be not earlier than the date of manufacture of the incomplete vehicle as shown on the incomplete vehicle manufacturer's label, pursuant to paragraph (a)(3) of this section, and not later than the date of completion of the final stage manufacture of the completed vehicle as shown on the final stage manufacturer's label, pursuant to paragraph (c)(2) of this section.

(d) More than one set of figures for GVWR and GAWR, and one or more tire sizes, may be listed in response to paragraphs (c)(5) and (6) of this section, as provided, in § 567.4(h) of this section.

(e) If an incomplete vehicle manufacturer assumes, with respect to the vehicle as finally manufactured, legal responsibility for all duties and liabilities imposed on the vehicle's manufacturer by the National Traffic and Motor Vehicle Safety Act, the incomplete vehicle manufacturer shall ensure that a label is affixed to the complete vehicle. Such label shall conform with the requirements of paragraph (c) of this section, except that the name of the incomplete vehicle manufacturer shall appear after the words "MANUFACTURED BY" or "MFD BY," instead of the name of the final stage manufacturer, as specified in paragraph (c)(1) of this section.

(f) If an intermediate manufacturer of the vehicle assumes, with respect to the vehicle as finally manufactured, legal responsibility for all duties and liabilities imposed on the vehicle's manufacturer by the National Traffic and Motor Vehicle Safety Act, the intermediate manufacturer shall ensure that a label is affixed to the completed vehicle. Such label shall conform with the requirements of paragraph (c) of this section, except that the name of the intermediate manufacturer shall appear after the words "MANUFACTURED BY" or "MFD BY," instead of the name of the final stage manufacturer, as

specified in paragraph (c)(1) of this section.

* * * * *

PART 568—[AMENDED]

4. The authority citation of part 568 would be revised to read as follows:

Authority: 15 U.S.C. 1392, 1401, 1403, 1407; delegation of authority at 49 CFR 1.50.

5. Section 568.5 would be revised to read as follows:

§ 568.5 Requirements for intermediate manufacturers.

(a) Each intermediate manufacturer of any incomplete vehicle shall furnish the incomplete vehicle document provided by the incomplete vehicle manufacturer, pursuant to § 568.4, at or before the time of delivery of the incomplete vehicle to any subsequent manufacturer or purchaser, in the manner specified in § 568.4 of this section.

(b) If any of the changes to the incomplete vehicle made by an intermediate manufacturer affect the validity of any of the statements or instructions in the incomplete vehicle document provided by the incomplete vehicle manufacturer, the intermediate manufacturer shall comply with paragraph (a) of this section and also furnish an addendum along with the incomplete vehicle document. The addendum shall contain:

(1) the full name of the intermediate manufacturer;

(2) a complete mailing address for the intermediate manufacturer; and

(3) a clear and specific indication of all changes that should be made to the incomplete vehicle document to reflect the intermediate manufacturer's operations on the incomplete vehicle.

6. Section 568.6 would be revised to read as follows:

§ 568.6 Requirements for final stage manufacturers.

(a) Each final stage manufacturer shall complete every one of its vehicles in such a manner that the vehicle conforms to the standards in effect on the date of manufacture of the incomplete vehicle, the date of completion of the final stage manufacture of the vehicle, or any date between those two dates. This requirement may, however, be superseded by any conflicting provisions of a standard that specifically provides for differing requirements for vehicles manufactured in two or more stages.

(b) Each final stage manufacturer shall affix to every one of its completed vehicles:

(1) any certification labels furnished with the incomplete vehicle document by the incomplete vehicle manufacturer, pursuant to § 567.5(a) of this chapter, and by any intermediate manufacturers, pursuant to § 567.5(b) of this chapter; and

(2) its own certification label, pursuant to § 567.5(c) of this chapter.

Issued on November 26, 1991.

Barry Felrice,

Associate Administrator for Rulemaking.

[FR Doc. 91-28870 Filed 12-2-91; 8:45am]

BILLING CODE 4910-59-M

Notices

Federal Register
Vol. 56, No. 232
Tuesday, December 3, 1991

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices of hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications and agency statements of organization and functions are examples of documents appearing in this section.

DEPARTMENT OF AGRICULTURE

Food Safety and Inspection Service

[Docket No. 91-038N]

National Advisory Committee on Microbiological Criteria for Foods; Meetings

Pursuant to the Federal Advisory Committee Act (5 U.S.C., appendix I), notice is hereby given that Subcommittee meetings of the National Advisory Committee on Microbiological Criteria for Foods will be held on Monday through Thursday, December 16–19, 1991, in Arlington, Virginia, at the Sheraton Crystal City Hotel, 1800 Jefferson Davis Highway, Arlington, Virginia 22202, telephone (703) 486–1111. The Committee provides advice and recommendations to the secretaries of Agriculture and Health and Human Services concerning the development of microbiological criteria by which the safety and wholesomeness of food can be assessed, including criteria for microorganisms that indicate whether foods have been produced using good manufacturing practices.

Scheduled sessions are as follows:

1. Monday, December 16, 12:30 p.m. to 4:30 p.m., and Tuesday, December 17, 8:30 a.m. to 4:30 p.m.—Sessions of the Hazard Analysis and Critical Control Points (HACCP) Subcommittee; and
2. Wednesday, December 18, 8:30 a.m. to 4:30 p.m. and Thursday, December 19, 8:30 a.m. to 12 noon—Sessions of the Seafood Subcommittee.

The Committee meetings are open to the public on a space available basis. Comments of interested persons may be filed prior to the meeting in order that they may be considered and should be addressed to Ms. Linda Hayden, Executive Secretariat, Food Safety and Inspection Service, U.S. Department of Agriculture, room 3175, South Agriculture Building, 14th and Independence Avenue, SW., Washington, DC 20250. In submitting comments, please reference the docket number appearing in the heading of this notice. Background materials are available for inspection by contacting Ms. Hayden on (202) 720–9150.

Done at Washington, DC on: November 25, 1991.

Ronald J. Prucha,

Acting Administrator.

[FR Doc. 91-28807 Filed 12-2-91; 8:45 am]

BILLING CODE 3410-DM-M

Forest Service

Breezin Timber Sales, Olympic National Forest, Clallam and Jefferson Counties, WA

AGENCY: Forest Service, USDA.

ACTION: Notice of intent to prepare an environmental impact statement.

SUMMARY: The Forest Service will prepare an environmental impact statement (EIS) to analyze and disclose the environmental impacts of a site specific proposal to harvest and regenerate timber, and to construct associated roads in the Breezin planning area. The Forest Service proposal would remove approximately 2.5 to 3.5 million board feet of timber blown down in the winter of 1990–1991, would harvest such additional standing timber as is necessary to facilitate removal of the blowdown, and would harvest additional areas as determined desirable to meet the management objectives of the area. The proposed timber sales will be in compliance with the 1990 Olympic National Forest Land and Resource Management Plan (Forest Plan). The project area includes a portion of the Green Mountain and Mt. Zion unroaded areas as described in appendix C of the Final EIS for the Forest Plan. The planning area is approximately 30 miles southeast of Port Angeles and 5 miles northwest of Quilcene, in the Penny Creek and Little Quilcene River drainages of the Quilcene Ranger District, Olympic National Forest, Washington. The agency gives notice of the environmental analysis and decision making process occurring on this Forest Service proposal so that Federal, State, and local agencies, tribes and other individuals or organizations who may be interested or affected by the proposal may participate and contribute to the final decision. The Olympic National Forest invites written input concerning issues specific to the proposed action.

DATES: Comments concerning the scope of the analysis should be received in writing by January 14, 1992.

ADDRESSES: Send written input about the Proposed Action to District Ranger, Quilcene Ranger District, P.O. Box 280, Quilcene, WA 98376.

FOR FURTHER INFORMATION CONTACT: Jim Halvorson, Presale Assistant, Quilcene Ranger District, P.O. Box 280, Quilcene, WA 98376. (206) 765–3368.

SUPPLEMENTARY INFORMATION: The Forest Service proposal is to implement management direction and projects identified in the Forest Plan. This EIS will be tiered to the Forest Plan which provides goals, objectives, standards and guidelines for the various activities and land allocation on the Forest. The proposed timber sales are derived in part from elements in the Forest Plan Ten Year Activity Schedule (appendix A).

Proposed timber sales include salvage of blowdown timber within the Green Mountain and Mt. Zion unroaded areas, commercial thinning and other timber harvest. Other projects to achieve the desired future condition identified in the Forest Plan may also be considered. Related actions include the construction and reconstruction of roads. The acquisition of additional road use easements or permits may be necessary.

Tentative issues that have been identified include: (1) Timber harvest in the Green Mountain and Mt. Zion unroaded areas; (2) Maintenance of water quality in the Little Quilcene River and Penny Creek; (3) Protection of the City of Port Townsend water pipeline and intake; (4) Maintenance and/or enhancement of Spotted Owl habitat; (5) Maintenance and/or enhancement of Pine Martin habitat; and (6) Creation of stand structural diversity.

A range of project alternatives will be considered including a no action alternative. The issues gathered through scoping will be used to formulate action alternatives. The action alternatives will vary as to (1) the amount and location of timber considered for treatment, (2) the amount of road construction and reconstruction, (3) the silvicultural and post harvest treatments proposed and

(4) the number, type and location of other integrated resource projects.

Public participation will be especially important at several points during the analysis. The Forest Service will be seeking information, comments, and assistance from Federal, State and local agencies, tribes and other individuals or organizations who may be interested or affected by the proposed actions. This information will be used in preparation of the draft EIS. The scoping process includes:

(1) Identification of potential issues.

(2) Identification of issues to be analyzed in depth.

(3) Elimination of insignificant issues or those which have been covered by a relevant previous environmental process.

(4) Exploration of additional alternatives.

(5) Identification of potential environmental effects of the proposed action and alternatives (i.e. direct, indirect, and cumulative effects and connected actions).

The draft EIS is expected to be filed with the Environmental Protection Agency (EPA) and to be available for public review by March, 1992. At that time the EPA will publish a notice of availability of the draft EIS in the Federal Register. The comment period on the draft EIS will be 45 days from the date the EPA publishes the notice of availability in the **Federal Register**.

The Forest Service believes it is important to give reviewers notice at this early stage of several court rulings related to public participation in the environmental review process. First, reviewers of a draft EIS must structure their participation in the environmental review of the proposal so that it is meaningful and alerts an agency to the reviewer's position and contentions. *Vermont Yankee Nuclear Power Corp* v. *NRDC*, 435 U.S. 519, 553 (1978). Also, environmental objections that could be raised at the draft EIS stage but that are not raised until after completion of the final EIS may be waived or dismissed by the courts. *City of Angoon* v. *Hodel*, 803 f.2d 1016, 1022 (9th Cir. 1986) and *Wisconsin Heritages, Inc.* v. *Harris*, 490 F. Supp. 1334, 1338 (E.D. Wis. 1980). Because of these court rulings, it is very important that those interested in this proposed action participate by the close of the 45-day comment period so that substantive comments and objections are made available to the Forest Service at a time when it can meaningfully consider them and respond to them in the final EIS.

To assist the Forest Service in identifying and considering issues and concerns on the proposed action, comments on the draft EIS should be a specific as possible. It is also helpful if comments refer to specific pages or chapters of the draft EIS. Comments may also address the adequacy of the draft EIS or the merits of the alternatives formulated and discussed in the statement. (Reviewers may wish to refer to the Council on Environmental Quality Regulations for implementing the procedural provisions of the National Environmental Policy Act at 40 CFR 1503.3 in addressing these points.).

The final EIS is scheduled to be completed by August, 1992. In the final EIS, the Forest Service is required to respond to comments and responses received during the comment period that pertain to the environmental consequences discussed in the draft EIS and applicable laws, regulations, and policies considered in making the decision regarding this proposal. The Forest Supervisor, Olympic National Forest, is the responsible official. The responsible official will document the decision and reasons for the decision in the Record of Decision. That decision will be subject to Forest Service Appeal Regulations 36 CFR part 217.

Dated: November 14, 1991.

Ronald R. Humphrey,

Forest Supervisor.

[FR Doc. 91-28903 Filed 12-2-91; 8:45 am]

BILLING CODE 3410-11-M

DEPARTMENT OF COMMERCE

International Trade Administration

[A-588-405]

Cellular Mobile Telephones and Subassemblies from Japan; Preliminary Results of Antidumping Duty Administrative Reviews

AGENCY: International Trade Administration/Import Administration, Department of Commerce.

ACTION: Notice of preliminary results of antidumping duty administrative reviews.

SUMMARY: In response to requests by the petitioner and a respondent, the Department of Commerce has conducted two administrative reviews of the antidumping duty order on cellular mobile telephones and subassemblies from Japan. The first of these reviews covers one manufacturer/exporter of this merchandise to the United States for the period December 1, 1988 through November 30, 1989. We preliminarily determine the dumping margin for this period to be 0.44 percent. The subsequent review covers one manufacturer/exporter of this merchandise to the United States for the period December 1, 1989 through November 30, 1990. We preliminarily determine the dumping margin for this period to be 19.41 percent. We invite interested parties to comment on these preliminary results.

EFFECTIVE DATE: December 3, 1991.

FOR FURTHER INFORMATION CONTACT: Cameron Cardozo, Anne D'Alauro, or Maria MacKay, Office of Countervailing Compliance, International Trade Administration, U.S. Department of Commerce, Washington, DC 20230; telephone: (202) 377-2786.

SUPPLEMENTARY INFORMATION:

Background

On December 21, 1989, the Department of Commerce (the Department) published in the **Federal Register** a notice of "Opportunity to Request Administrative Review" (54 FR 52436) of the antidumping duty order on cellular mobile telephones and subassemblies from Japan for the period December 1, 1988 through November 30, 1989. On December 29, 1989, the petitioner, Motorola, Inc., requested an administrative review of one manufacturer/exporter, Mitsubishi Electric Corporation (MELCO). We initiated the review on February 16, 1990 (55 FR 5640).

On December 12, 1990, the Department published in the **Federal Register** a notice of "Opportunity to Request Administrative Review" (55 FR 51139) of the antidumping duty order on cellular mobile telephones and subassemblies from Japan for the period December 1, 1989 through November 30, 1990. On December 31, 1990, one manufacturer/exporter, Murata Manufacturing Company, Ltd. (MMC), requested an administrative review. We initiated the review on February 19, 1991 (56 FR 6621). The Department has now conducted these administrative reviews in accordance with section 751 of the Tariff Act of 1930, as amended (the Tariff Act).

Scope of the Review

Imports covered by these reviews are cellular mobile telephones (CMTs), CMT transceivers, CMT control units, and certain subassemblies thereof, which meet the tests set forth below. CMTs are radio-telephone equipment designed to operate in a cellular radio-telephone system, *i.e.*, a system that permits mobile telephones to communicate with traditional land-line telephones via a base station, and that permits multiple simultaneous use of particular radio

frequencies through the division of the system into independent cells, each of which has its own transceiving base station. Each CMT generally consists of (1) a transceiver, *i.e.*, a box of electronic subassemblies which receives and transmits calls; and (2) a control unit, *i.e.*, a handset and cradle resembling a modern telephone, which permits a motor-vehicle driver or passenger to dial, speak, and hear a call. They are designed to use motor vehicle power sources. Cellular transportable telephones, which are designed to use either motor vehicle power sources or, alternatively, portable power sources, are included in this antidumping duty order.

Subassemblies are any completed or partially completed circuit modules, the value of which is equal to or greater than five dollars and which are dedicated exclusively for use in CMT transceivers or control units. The term "dedicated exclusively for use" only encompasses those subassemblies that are specifically designed for use in CMTs, and could not be used, absent alteration, in a non-CMT device. The Department selected the five dollar value for defining the scope since this is a value that it has determined is equivalent to a "major" subassembly. The Department feels that a dollar cutoff point is a more workable standard than a subjective determination such as whether a circuit module is "substantially complete." Examples of subassemblies which may fall within this definition are circuit modules containing any of the following circuitry or combinations thereof: Audio processing, signal processing (logic), RF, IF, synthesizer, duplexer, power supply, power amplification, transmitter and exciter. The presumption is that CMT subassemblies are covered by the order unless an importer can prove otherwise. An importer will have to file a declaration with the Customs Service to the effect that a particular CMT subassembly is not dedicated exclusively for use in CMTs or that the dollar value is less than $5, if he wishes it to be excluded from the order.

The following merchandise has been excluded from this order: pocket-size self-contained portable cellular telephones, cellular base stations or base station apparatus, cellular switches, and mobile telephones designed for operation on other, non-cellular, mobile telephone systems.

Through 1988, cellular mobile telephones and subassemblies were classified under item numbers 685.28 and 685.33 of the Tariff Schedules of the United States (TSUS); they are currently classified under item numbers 8525.20.60, 8525.10.80, 8527.90.80, 8529.10.60, 8529.90.50, 8542.20.00 and 8542.80.00 of the Harmonized Tariff Schedule (HTS). The TSUS and HTS item numbers are provided for convenience and Customs purposes. The written product description remains dispositive.

The review for the period December 1, 1988 through November 30, 1989 covers one manufacturer/exporter, MELCO, of cellular mobile telephones and subassemblies to the United States. The review of the December 1, 1989 through November 30, 1990 period covers one manufacturer/exporter, MMC.

United States Price

In calculating United States price, the Department used purchase price and exporter's sales price, as defined in section 772 of the Tariff Act. For those sales made directly to unrelated parties prior to importation into the United States, we based the United States price on purchase price, in accordance with section 772(b) of the Act. In those cases where sales were made through a related sales agent in the United States to an unrelated purchaser prior to the date of importation, we also used purchase price as the basis for determining United States price. For the latter sales, the Department determined that purchase price was the appropriate determinant of United States price because the merchandise was shipped immediately after importation from the related sales agent to the unrelated buyers, without being introduced into the inventory of the related selling agent, except where a customer's order was subject to just-in-time delivery instructions. Moreover, this arrangement was the customary commercial channel for sales of this merchandise between the parties involved. Finally, the related selling agent located in the United States acted mainly as a processor of sales-related documentation and a communication link with the unrelated U.S. buyers.

Where all the above elements are met, we regard the routine selling functions of the exporter as merely having been relocated geographically from the country of exportation to the United States, where the sales agent performs them. Whether these functions take place in the United States or abroad does not change the substance of the transactions or the functions themselves.

Where sales to the first unrelated purchaser occurred after importation into the United States, we based United States price on exporter's sales price, in accordance with section 772(c) of the Tariff Act. Purchase price and exporter's sales price were based on the packed, f.o.b. Japan and f.o.b. United States, price to unrelated purchasers in the United States. We made adjustments, where applicable, for inland freight and insurance, air freight and insurance, ocean freight, brokerage, foreign inland freight, import duties, indirect selling expenses, commissions, and credit.

Foreign Market Value

In calculating foreign market value, the Department used home market price, as defined in section 773 of the Tariff Act, since sufficient quantities of such or similar merchandise were sold in the home market to provide a basis for comparison. Home market price was based on the packed, ex-factory or delivered price to unrelated purchasers in the home market. Where applicable, we made adjustments for inland freight and insurance, credit expenses, discounts, rebates, direct selling expenses, physical differences in the merchandise, and differences in packing. For exporter's sales price sales, we deducted home market indirect selling expenses up to the amount of U.S. indirect selling expenses plus U.S. commissions. For purchase price sales, we deducted home market indirect selling expenses up to the amount of the U.S. commission, and then added the U.S. commission to the home market price.

Preliminary Results of the Reviews

As a result of our reviews, we preliminarily determine the dumping margins to be:

Manufacturer/exporter	Review period	Margin (percent)
Mitsubishi Electric Corporation (MELCO)	12/1/88–11/30/89	0.44
Murata Manufacturing Company, Ltd. (MMC)	12/1/89–11/30/90	19.41

The Department will publish the final results of these administrative reviews including the results of its analysis of issues raised in any case or rebuttal brief or at a hearing.

Parties to the proceeding may request disclosure and interested parties may request a hearing not later than 10 days after publication of this notice. Interested parties may submit written arguments in case briefs on these preliminary results within 30 days of the date of publication. Rebuttal briefs, limited to arguments raised in case briefs, may be submitted seven days after the time limit for filing the case brief. Any hearing, if requested, will be held seven days after the scheduled date for submission of rebuttal briefs. Copies of case briefs and rebuttal briefs must be served on interested parties in accordance with 19 CFR 353.38(e). Representatives of parties to the proceeding may request disclosure of proprietary information under administrative protective order no later than 10 days after the representative's client or employer becomes a party to the proceeding, but in no event later than the date the case briefs are due.

The Department shall determine, and the Customs Service shall assess, antidumping duties on all appropriate entries. Individual differences between United States price and foreign market value may vary from the percentages stated above. The Department will issue appraisement instructions directly to the Customs Service.

Furthermore, the following deposit requirements will be effective upon publication of the final results of these administrative reviews for all shipments of Japanese cellular mobile telephones and subassemblies entered, or withdrawn from warehouse, for consumption on or after the publication date, as provided by section 751(a)(1) of the Tariff Act: (1) The cash deposit rate for the reviewed companies will be that established in the final results of these administrative reviews; (2) for merchandise exported by manufacturers or exporters not covered in these reviews but covered in previous reviews or the original less-than-fair-value investigation, the cash deposit rate will continue to be the rate published in the most recent determination for which the manufacturer or exporter received a company-specific rate; and (3) the cash deposit rate for all other manufacturers or exporters will be 19.41 percent. These deposit requirements, when imposed, shall remain in effect until publication of the final results of the next administrative review.

These administrative reviews and notice are in accordance with section 751(a)(1) of the Tariff Act, as amended (19 U.S.C. 1675(a)(1)) and 19 CFR 353.22.

Dated: November 25, 1991.

Francis J. Sailer,

Acting Assistant Secretary for Import Administration.

[FR Doc. 91-28979 Filed 12-2-91; 8:45 am]

BILLING CODE 3510-05-M

International Trade Administration

[C-549-401]

Noncontinuous Noncellulosic Yarns From Thailand; Preliminary Results of Countervailing Duty Administrative Review

AGENCY: International Trade Administration/Import Administration Department of Commerce.

ACTION: Notice of preliminary results of countervailing duty administrative review.

SUMMARY: The Department of Commerce has conducted an administrative review of the agreement suspending the countervailing duty investigation on noncontinuous noncellulosic yarns from Thailand. The review covers the period January 1, 1990 through December 31, 1990. There are no known shipments during the review period. We preliminarily determine that the Government of Thailand and the exporters of noncontinuous noncellulosic yarns have complied with the terms of the suspension agreement. We invite interested parties to comment on these results.

EFFECTIVE DATE: December 3, 1991.

FOR FURTHER INFORMATION CONTACT: Robert Bolling or Wendy Frankel, Office of Agreements Compliance, International Trade Administration, U.S. Department of Commerce, Washington, DC 20230; telephone: (202) 377-3793.

SUPPLEMENTARY INFORMATION:

Background

On March 12, 1985, the Department (the Department) published a notice of suspension of the countervailing duty investigation on Certain Textile Mill Products from Thailand (50 FR 9832; March 12, 1985). On March 8, 1991, the Department of Commerce published in the **Federal Register** a notice of "Opportunity to Request Administrative Review" (56 FR 9936) of the suspension agreement for the period January 1, 1990 through December 31, 1990. On March 22, 1991, an interested party, the American Yarn Spinners Association, Inc. (AYSA), requested an administrative review of the suspended investigation. We initiated the review on April 18, 1991 (56 FR 15856). As a result of litigation, the Department terminated the suspended investigation with respect to all products but noncontinuous noncellulosic yarns (56 FR 54838; October 23, 1991). The Department is now conducting this review in accordance with section 751 of the Tariff Act of 1930, as amended (the Tariff Act).

Scope of Review

Imports covered by this review are shipments of noncontinuous noncellulosic yarns from Thailand. During the period of review, such merchandise was classifiable under items 5509.21.0000, 5509.22.0010, 5509.22.0090, 5509.32.0000, 5509.51.3000, 5509.51.6000, and 5509.69.4000 of the *Harmonized Tariff Schedule* (HTS). The HTS item numbers are provided for convenience and Customs purposes. The written description remains dispositive.

The review covers the period January 1, 1990 through December 31, 1990 and six programs: (1) Export Packing Credits; (2) Rediscount of Industrial Bills; (3) Electricity Discounts for Exporters; (4) Tax Certificates for Exports; (5) Foreign Marketing Expenses; and (6) Flat Rate Tax Rebates.

In its questionnaire response, the Government of Thailand reported that there were no known shipments of the subject merchandise to the United States during the review period. The United States Customs Service has indicated to the Department that there were no known shipments of this merchandise during the review period.

Preliminary Results of Review

The suspension agreement on Certain Textile Mill Products from Thailand provides that producers/exporters in Thailand will not receive certain benefits which benefit the subject merchandise exported to the United States (See 50 FR 9832; March 12, 1985).

Because the Government of Thailand and the United States Customs Service have indicated that there were no known shipments of the subject merchandise exported to the United States during the review period, we preliminarily determine that the Government of Thailand and the exporters have complied with the terms of the suspension agreement.

Interested parties may submit written comments on these preliminary results within 30 days of the date of publication of this notice and may request disclosure and/or a hearing within 10 days of the date of publication. Any hearing, if requested, will be held 44 days after the date of publication or the

first workday thereafter. Rebuttal briefs and rebuttals to written comments, limited to issues in those comments, may be filed not later than 37 days after the date of publication. The Department will publish the final results of its analysis of issues raised in any such written comments.

This administrative review and notice are in accordance with section 751(a)(1) of the Tariff Act (19 U.S.C. 1675(a)(1)) and 19 CFR 355.22.

Dated: November 22, 1991.

Francis J. Sailer,

Acting Assistant Secretary for Import Administration.

[FR Doc. 91-28980 Filed 12-2-91; 8:45 am]

BILLING CODE 3510-DS-M

COMMITTEE FOR THE IMPLEMENTATION OF TEXTILE AGREEMENTS

Adjustment of Import Limits for Certain Cotton and Man-Made Fiber Textile Products Produced or Manufactured in Singapore

November 26, 1991.

AGENCY: Committee for the Implementation of Textile Agreements (CITA).

ACTION: Issuing a directive to the Commissioner of Customs adjusting limits.

EFFECTIVE DATE: December 4, 1991.

FOR FURTHER INFORMATION CONTACT: Jennifer Tallarico, International Trade Specialist, Office of Textiles and Apparel, U.S. Department of Commerce, (202) 377-4212. For information on the quota status of these limits, refer to the Quota Status Reports posted on the bulletin boards of each Customs port or call (202) 535-6736. For information on embargoes and quota re-openings, call (202) 377-3715.

SUPPLEMENTARY INFORMATION:

Authority: Executive Order 11651 of March 3, 1972, as amended; section 204 of the Agricultural Act of 1956, as amended (7 U.S.C. 1854).

The current limits for certain categories are being adjusted, variously, for swing and carryforward.

A description of the textile and apparel categories in terms of HTS numbers is available in the CORRELATION: Textile and Apparel Categories with the Harmonized Tariff Schedule of the United States (see **Federal Register** notice 55 FR 50756, published on December 10, 1990). Also see 55 FR 51756, published on December 17, 1990.

The letter to the Commissioner of Customs and the actions taken pursuant to it are not designed to implement all of the provisions of the bilateral agreement, but are designed to assist only in the implementation of certain of its provisions.

Auggie D. Tantillo,

Chairman, Committee for the Implementation of Textile Agreements.

Committee for the Implementation of Textile Agreements

November 26, 1991.

Commissioner of Customs,

Department of the Treasury, Washington, DC 20229.

Dear Commissioner: This directive amends, but does not cancel, the directive issued to you on December 11, 1990, by the Chairman, Committee for the Implementation of Textile Agreements. That directive concerns imports of certain cotton, wool and man-made fiber textile products, produced or manufactured in Singapore and exported during the twelve-month period which began on January 1, 1991 and extends through December 31, 1991.

Effective on December 4, 1991, you are directed to amend further the directive dated December 11, 1990 to adjust the limits for the following categories, as provided under the terms of the current bilateral agreement between the Governments of the United States and Singapore:

Category	Adjusted twelve-month limit [1]
Levels in Group I	
239	414,952 kilograms.
334	60,950 dozen.
335	109,436 dozen.
338/339	1,008,825 dozen of which not more than 550,996 dozen shall be in Category 338 and not more than 612,638 dozen shall be in Category 339.
340	669,345 dozen.
347/348	893,104 dozen of which not more than 521,673 dozen shall be in Category 347 and not more than 405,746 dozen shall be in Category 348.
638	696,902 dozen.
639	3,451,165 dozen.
640	105,160 dozen.
645/646	127,696 dozen.
647	445,180 dozen.
648	1,534,710 dozen.
Sublevels in Group II	
222	375,240 kilograms.
237	204,859 dozen.

[1] The limits have not been adjusted to account for any imports exported after December 31, 1990.

The Committee for the Implementation of Textile Agreements has determined that these actions fall within the foreign affairs exception to the rulemaking provisions of 5 U.S.C. 553(a)(1).

Sincerely,

Auggie D. Tantillo,

Chairman, Committee for the Implementation of Textile Agreements.

[FR Doc. 91-28899 Filed 12-2-91; 8:45 am]

BILLING CODE 3510-DR-F

Adjustment of Import Limits for Certain Cotton, Wool, Man-Made Fiber, Silk Blend and Other Vegetable Fiber Textiles and Textile Products Produced or Manufactured in Taiwan

November 26, 1991.

AGENCY: Committee for the Implementation of Textile Agreements (CITA).

ACTION: Issuing a directive to the Commissioner of Customs adjusting limits.

EFFECTIVE DATE: November 26, 1991.

FOR FURTHER INFORMATION CONTACT: Jennifer Tallarico, International Trade Specialist, Office of Textiles and Apparel, U.S. Department of Commerce, (202) 377-4212. For information on the quota status of these limits, refer to the Quota Status Reports posted on the bulletin boards of each Customs port or call (202) 566-8791. For information on embargoes and quota re-openings, call (202) 377-3715.

SUPPLEMENTARY INFORMATION:

Authority: Executive Order 11651 of March 3, 1972, as amended; section 204 of the Agricultural Act of 1956, as amended (7 U.S.C. 1854).

The current limits for certain categories are being adjusted, variously, for swing, carryforward and cancellation of special shift.

A description of the textile and apparel categories in terms of HTS numbers is available in the CORRELATION: Textile and Apparel Categories with the Harmonized Tariff Schedule of the United States (see **Federal Register** notice 55 FR 50756, published on December 10, 1990). Also see 55 FR 50862, published on December 11, 1990.

The letter to the Commissioner of Customs and the actions taken pursuant to it are not designed to implement all of the provisions of the bilateral agreement, but are designed to assist only in the implementation of certain of its provisions.

Auggie D. Tantillo,

Chairman, Committee for the Implementation of Textile Agreements.

Committee for the Implementation of Textile Agreements

November 26, 1991.

Commissioner of Customs,

Department of the Treasury, Washington, DC 20229.

Dear Commissioner: This directive amends, but does not cancel, the directive issued to you on December 5, 1990, by the Chairman, Committee for the Implementation of Textile Agreements. That directive concerns imports of certain cotton, wool, man-made fiber, silk blend and other vegetable fiber textiles and textile products, produced or manufactured in Taiwan and exported during the twelve-month period which began on January 1, 1991 and extends through December 31, 1991.

Effective on November 26, 1991, you are directed to amend further the directive dated December 5, 1990 to adjust the limits for the following categories, as provided under the terms of the bilateral agreement, effected by exchange of notes dated August 21, 1990 and September 28, 1990:

Category	Adjusted twelve-month limit [1]
Group I	
200–224, 225/317/326, 226, 227, 229, 300/301/607, 313–315, 360–363, 369–L/670–L/870 [2], 369–S [3], 369–O [4], 400–414, 464–469, 600–606, 611, 613/614/615/617, 618, 619/620, 621–624, 625/626/627/628/629, 665, 666, 669–P [5], 669–T [6], 669–O [7], 670–H [8] and 670–O [9], as a group.	566,563,892 square meters equivalent.
Sublevels in Group I	
200	626,140 kilograms.
218	19,377,976 square meters.
225/317/326	34,395,854 square meters.
361	1,257,776 numbers.
613/614/615/616/617.	17,322,667 square meters.
625/626/627/628/629.	16,567,915 square meters.
Group II	
237, 239, 330–332, 333/334/335, 336, 338/339, 340–345, 347/348, 349, 350/650, 351, 352/652, 353, 354, 359–C/659–C [10], 359–H/659–H [11], 359–O [12], 431-444, 445/446, 447/448, 459, 630–632, 633/634/635, 636, 638/639, 640, 641–644, 645/646, 647/648, 649, 651, 653, 654, 659–S [13], 659–O [14], 831-844 and 846–859, as a group.	791,255,378 square meters equivalent.
Sublevels in Group II	
331	519,202 dozen pairs.
336	112,605 dozen.
338/339	834,217 dozen.
340	1,362,270 dozen.
341	317,726 dozen.
342	183,214 dozen.
345	107,566 dozen.
351	288,545 dozen.
359–H/659–H	4,862,897 kilograms.
435	21,462 dozen.
444	103,247 numbers.
445/446	138,622 dozen.
631	4,619,117 dozen pairs.
633/634/635	1,747,960 dozen of which not more than 1,037,501 dozen shall be in Categories 633/634 and not more than 899,673 dozen shall be in Category 635.
636	372,210 dozen.
638/639	6,977,049 dozen.
641	780,939 dozen of which not more than 269,070 dozen shall be in Category 641–Y [15].
642	857,329 dozen.
644	899,883 numbers.
647/648	5,945,086 dozen.
651	514,938 dozen.

[1] The limits have not been adjusted to account for any imports exported after December 31, 1990.

[2] Category 870; Category 369–L: only HTS numbers 4202.12.4000, 4202.12.8020, 4202.12.8060, 4202.92.1500, 4202.92.3015 and 4202.92.6000; Category 670–L: only HTS numbers 4202.12.8030, 4202.12.8070, 4202.92.3020, 4202.92.3030 and 4202.92.9020.

[3] Category 369–S: only HTS number 6307.10.2005.

[4] Category 669–P: only HTS numbers 6305.31.0010, 6305.31.0020 and 6305.39.0000.

[5] Category 369–O: all HTS numbers except 4202.12.4000, 4202.12.8020, 4202.12.8060, 4202.92.1500, 4202.92.3015, 4202.92.6000 (Category 369–L); and 6307.10.2005 (Category 369–S).

[6] Category 669–T: only HTS numbers 6306.12.0000, 6306.19.0010 and 6306.22.9030.

[7] Category 669–O: all HTS numbers except 6305.31.0010, 6305.31.0020, 6305.39.0000 (Category 669–P); 6306.12.0000, 6306.19.0010 and 6306.22.9030 (Category 669–T).

[8] Category 670–H: only HTS numbers 4202.22.4030 and 4202.22.8050.

[9] Category 670–O: all HTS numbers except 4202.22.4030, 4202.22.8050 (Category 670–H); 4202.12.8030, 4202.12.8070, 4202.92.3020, 4202.92.3030 and 4202.92.9020 (Category 670–L).

[10] Category 359–C: only HTS numbers 6103.42.2025, 6103.49.3034, 6104.62.1020, 6104.69.3010, 6114.20.0048, 6114.20.0052, 6203.42.2010, 6203.42.2090, 6204.62.2010, 6211.32.0010, 6211.32.0025 and 6211.42.0010; Category 659–C: only HTS numbers 6103.23.0055, 6103.43.2020, 6103.49.2000, 6103.49.3038, 6104.63.1020, 6104.69.1000, 6104.69.3014, 6114.30.3044, 6114.30.3054, 6203.43.2010, 6203.43.2090, 6203.49.1010, 6203.49.1090, 6204.63.1510, 6204.69.1010, 6210.10.4015, 6211.33.0010, 6211.33.0017 and 6211.43.0010.

[11] Category 359–H: only HTS numbers 6505.90.1540 and 6505.90.2060; Category 659–H: only HTS numbers 6502.00.9030, 6504.00.9015, 6504.00.9060, 6505.90.5090, 6505.90.6090, 6505.90.7090 and 6505.90.8090.

[12] Category 359–O: all HTS numbers except 6103.42.2025, 6103.49.3034, 6104.62.1020, 6104.69.3010, 6114.20.0048, 6114.20.0052, 6203.42.2010, 6203.42.2090, 6204.62.2010, 6211.32.0010, 6211.32.0025, 6211.42.0010 (Category 359–C); 6505.90.1540 and 6505.90.2060 (Category 359–H).

[13] Category 659–S: only HTS numbers 6112.31.0010, 6112.31.0020, 6112.41.0010, 6112.41.0020, 6112.41.0030, 6112.41.0040, 6211.11.1010, 6211.11.1020, 6211.12.1010 and 6211.12.1020.

[14] Category 659–O: all HTS numbers except 6103.23.0055, 6103.43.2020, 6103.49.2000, 6103.49.3038, 6104.63.1020, 6104.69.1000, 6104.69.3014, 6114.30.3044, 6114.30.3054, 6203.43.2010, 6203.43.2090, 6203.49.1010, 6203.49.1090, 6204.63.1510, 6204.69.1010, 6210.10.4015, 6211.33.0010, 6211.33.0017, 6211.43.0010 (Category 659–C); 6502.00.9030, 6504.00.9015, 6504.00.9060, 6505.90.5090, 6505.90.6090, 6505.90.7090, 6505.90.8090 (Category 659–H); 6112.31.0010, 6112.31.0020, 6112.41.0010, 6112.41.0020, 6112.41.0030, 6112.41.0040, 6211.11.1010, 6211.11.1020, 6211.12.1010 and 6211.12.1020 (Category 659–S).

[15] Category 641–Y: only HTS numbers 6204.23.0050, 6204.29.2030, 6206.40.3010 and 6206.40.3025.

The Committee for the Implementation of Textile Agreements has determined that these actions fall within the foreign affairs exception to the rulemaking provisions of 5 U.S.C. 553(a)(1).

Sincerely,

Auggie D. Tantillo,

Chairman, Committee for the Implementation of Textile Agreements.

[FR Doc. 91–28900 Filed 12–2–91; 8:45 am]

BILLING CODE 3510-DR-F

COMMODITY FUTURES TRADING COMMISSION

Chicago Mercantile Exchange Proposal To Expand its Cross-Margining Program With The Options Clearing Corporation To Include the Cross-Exchange Net Margining of the Positions of Market Professionals; Order

The Chicago Mercantile Exchange ("CME") has submitted to the Commodity Futures Trading Commission ("Commission"), pursuant to section 5a(12) of the Commodity Exchange Act ("Act"), 7 U.S.C. 7a(12), and Commission Regulation 1.41(b), 17 CFR 1.41(b), a proposal to expand its cross-margining program with The Options Clearing Corporation ("OCC") (CME and OCC together being the "participating clearing organizations") to include the cross-exchange net margining of the positions in specified commodity futures, commodity options, and securities options ("eligible contracts") of certain market professionals. These market professionals include CME members and firms owning CME memberships and market makers, specialists, and registered traders on securities options markets whose accounts would not be proprietary within the meaning of Commission Regulation 1.3(y), 17 CFR 1.3(y), ("participating market professionals") and whose positions are carried by participating futures commission merchants ("FCMs") that also are participating broker-dealers ("B/D") or by participating FCMs and their affiliated participating B/Ds which may also be FCMs (together "participating clearing firms").

Section 5a(12) of the Act provides that the Commission shall approve contract market rules only if such rules "are determined by the Commission not to be in violation of (the) Act or the regulations of the Commission." Commingling of futures and non-futures funds of customers currently is not permitted under the Commission's regulations. Section 4d(2) of the Act, 7 U.S.C. 6d(2), however, authorizes the Commission to issue an order prescribing the terms and conditions under which "money, securities, and property (received by an FCM to margin, guarantee, or secure the commodity futures trades or contracts of a customer) may be commingled * * * with any other money, securities, and property received by such (FCM) and required by the Commission to be separately accounted for and treated and dealt with as belonging to the customers of such (FCM)." Accordingly, any proposal which would permit such commingling would require Commission action pursuant to section 4d(2) of the Act, as well as section 5a(12).

Whereas, The CME-OCC non-proprietary cross-margining proposal provides for calculation by the participating clearing organizations of a single margin requirement to support the positions of participating market professionals in eligible contracts carried by participating clearing firms;

Whereas, The Commission has reviewed the CME-OCC cross-margining proposal, the proposed agreement between the participating clearing organizations, the proposed agreements among the participating clearing firms and the participating clearing organizations, and the proposed agreements among the participating market professionals and participating clearing firms submitted by letter dated January 30, 1990, the amendments thereto through November 22, 1991, the representations of the participating clearing organizations as to the operation of the program, the representations of the Securities Investor Protection Corporation ("SIPC") and the Securities and Exchange Commission ("SEC"), and such other documents as constitute the complete record in this matter ("Record");

Whereas, The agreements among participating market professionals, participating clearing firms, and participating clearing organizations require that:

(a) Each participating market professional acknowledge in writing that any money, securities, or property, including securities option positions, held on his behalf in a non-proprietary cross-margining account ("cross-margining property") will be treated in a manner consistent with the terms of this Order and any other applicable order issued by the Commission;

(b) Each participating market professional acknowledge and agree in writing that any cross-margining property held on his behalf by a participating FCM or a participating B/D affiliated with a participating FCM will be customer property deemed to be received by the participating FCM to be accounted for, treated, and dealt with by such FCM as belonging to such market professional in a manner consistent with section 4d of the Act;

(c) Each participating market professional agree in writing that, in the event of the bankruptcy, liquidation, or receivership of or other proceeding involving the distribution of funds held by a participating clearing firm against which such market professional has a customer net equity claim in respect of cross-margining property, such claim shall be subordinated to the customer net equity claims of "public customers," as that term is defined in Commission Regulation 190.01(hh), 17 CFR 190.01(hh), of such clearing firm that do not relate to money, securities, or property in any cross-margining account; and

(d) Each participating market professional acknowledge and agree in writing that cross-margining property held for or on his behalf will not be customer property under the Federal securities laws to the extent necessary to effect this Order and will not be customer property under subchapter III of chapter 7 of title 11 of the Bankruptcy Code, 11 U.S.C. 741–752 or the Securities Investor Protection Act ("SIPA"), 15 U.S.C. 78aaa *et seq.*, and will not be claimed as such, and will be customer property under the Act, subchapter IV of chapter 7 of title 11 of the Bankruptcy Code, 11 U.S.C. 761–766, and part 190 of the Commission's regulations, 17 CFR part 190;

Whereas, Each participating market professional which signed such a participant agreement will be a customer of a participating FCM;

Whereas, Each participating clearing firm will treat money, securities, and property received in respect of all accounts other than cross-margining accounts in a manner consistent with the requirements of the Commission and the SEC appropriate thereto;

Whereas, SIPC has represented that it has no objection to the agreements under which a participating market professional's cross-margining property would not be deemed to be customer property for purposes of the SIPA; and

Whereas, The SEC has concurred with the treatment of securities positions and cross-margining accounts set forth in this Order;

Now Therefore, Based on the Record in this matter, and provided that the cross-margining proposal submitted by CME is implemented consistently with the representations and agreements cited herein, and provided that:

(a) Each participating clearing organization, participating clearing firm, and participating market professional execute the agreements referred to herein;

(b) Each participating clearing organization, participating clearing firm, and depository separately account for cross-margining property maintained in non-proprietary cross-margining accounts and not commingle such cross-margining property with money, securities, and property maintained in any non-cross-margining accounts or proprietary cross-margining accounts;

(c) Each participating clearing organization, participating clearing firm, participating market professional, and depository provide the Commission with access to its books and records with respect to non-proprietary cross-margining accounts and positions in a manner consistent with Commission Regulation 1.31, 17 CFR 1.31;

(d) Each participating clearing firm include all cross-margining property received from participating market professionals as provided herein to margin, guarantee, or secure commodity futures trades, commodity futures contracts, commodity option transactions, or securities option transactions, or accruing to such participating market professionals as a result of such trades, contracts, commodity option transactions, or securities option transactions, when calculating segregation requirements for purposes of section 4d of the Act;

(e) Each participating clearing firm compute total segregation requirements under Section 4d of the Act and Commission Regulation 1.32, 17 CFR 1.32, by calculating separately the requirements for cross-margining and non-cross-margining accounts without using any net liquidating equity in one account to reduce a deficit in the other;

(f) Each participating clearing firm designate non-proprietary cross-margining accounts and positions as such in its books and records, including both internal documents maintained at the firms and account statements sent to participating market professionals;

(g) Each participating clearing organization calculate the margin requirement for each non-proprietary

cross-margining account separately from the margin requirements for other accounts, including proprietary cross-margining accounts; collect any margin required with respect to non-proprietary cross-margining accounts separately without applying any margin in any such account to satisfy a margin requirement in any proprietary account or any non-cross-margining customer account and without applying any margin in a non-cross-margining customer account to satisfy a margin requirement in any proprietary account or any non-proprietary cross-margining account; and maintain all cross-margining property received from participating clearing firms to margin, guarantee, or secure commodity futures trades, commodity futures contracts, commodity option transactions, or securities option transactions that are effected for non-proprietary cross-margining accounts or held in such accounts, and all accruals resulting from such trades, contracts, commodity option transactions, or securities option transactions, separately from money, securities, and property received to margin, guarantee, or secure commodity futures trades, commodity futures contracts, commodity option transactions, or securities option transactions that are effected for or held in any proprietary account or any non-cross-margining customer account, and related accruals; and

(h) Each participating clearing organization satisfy any deficiency in a non-proprietary cross-margining account without recourse to non-cross-margining segregated funds;

(i) Notwithstanding the foregoing, a participating clearing firm may commingle cross-margining property maintained in respect of the non-proprietary cross-margining arrangement between OCC and CME with money, securities, and property maintained in respect of similar non-proprietary cross-margining arrangements between OCC and other commodity clearing organizations or between CME and other commodity clearing organizations approved by the Commission, and may apply such commingled money, securities, and property to meet its obligations to a commodity or option clearing organization arising from trades or positions held in its non-proprietary cross-margining account established pursuant to one or more of such cross-margining arrangements, provided that the participating clearing firm:

(i) Separately identify and account for the money, securities, and property held pursuant to each of the non-proprietary cross-margining arrangements; and

(ii) Separately calculate the margin requirements with respect to each of the non-proprietary cross-margining arrangements, treating each position as being held pursuant to only one such arrangement;

It Is Hereby Ordered Pursuant to section 4d(2) of the Act:

(1) That all money, securities, and property received by a participating FCM or a participating B/D affiliated with a participating FCM to margin, guarantee, or secure securities option trades or contracts carried in a non-proprietary cross-margining account for or on behalf of participating market professionals, or accruing as a result of such trades or contracts, and held subject to the terms of this Order, shall be deemed to have been received by the participating FCM and shall be accounted for and treated and dealt with as belonging to the participating market professional customers of the participating FCM consistently with section 4d of the Act;

(2) That, subject to the terms of this Order, notwithstanding any provision to the contrary in the Commission's regulations (including, but not limited to, Regulations 1.20(a), 1.22, and 1.24, 17 CFR 1.20(a), 1.22 and 1.24), the money, securities, and property described in the preceding paragraph of this Order may be commingled in a non-proprietary cross-margining account with money, securities, and property received by a participating FCM to margin, guarantee, or secure trades or positions in eligible commodity futures or commodity option contracts, or accruing as a result of such trades or contracts, and otherwise required by the Commission to be segregated under the Act; and

(3) That, in the event of the bankruptcy, liquidation, or receivership of or other proceeding involving the distribution of funds held by a participating clearing firm, any customer net equity claim which a participating market professional has in respect of cross-margining property held by such participating clearing firm in a non-proprietary cross-margining account shall be treated as a customer net equity claim, under part 190 of the Commission's regulations and subchapter IV of chapter 7 of title 11 of the Bankruptcy Code, but shall be subordinated to the customer net equity claims of "public customers," as that term is defined in Commission Regulation 190.01(hh), of such clearing firm that do not relate to cross-margining property.

It Is Further Ordered, Pursuant to section 5a(12) of the Act and based upon the Commission action in the three preceding paragraphs of this Order, that the CME's request for Commission approval of its proposal to expand its cross-margining program with OCC to include the cross-exchange net margining of the positions of certain market professionals is hereby granted.

Issued in Washington, DC, this 26th day of November, 1991. By the Commission.

Jean A. Webb,

Secretary of the Commission.

[FR Doc 91-28861 Filed 12-2-01; 8:45 am]

BILLING CODE 6351-01-M

The Intermarket Clearing Corporation Proposal To Expand its Cross-Margining Program With The Options Clearing Corporation To Include the Cross-Exchange Net Margining of the Positions of Market Professionals; Order

The Intermarket Clearing Corporation ("ICC") has submitted to the Commodity Futures Trading Commission ("Commission"), pursuant to section 5a(12) of the Commodity Exchange Act ("Act"), 7 U.S.C. 7a(12), and Commission Regulation 1.41(b), 17 CFR 1.41(b), a proposal to expand its cross-margining program with The Options Clearing Corporation ("OCC") (ICC and OCC together being the "participating clearing organizations") to include the cross-exchange net margining of the positions in specified commodity futures, commodity options, and securities options ("eligible contracts") of certain market professionals. These market professionals include members of exchanges cleared by ICC and market makers, specialists, registered traders, stock market makers, and stock specialists on securities options markets whose accounts would not be proprietary within the meaning of Commission Regulation 1.3(y), 17 CFR 1.3(y), ("participating market professionals") and whose positions are carried by participating futures commission merchants ("FCMs") that also are participating broker-dealers ("B/Ds") or by participating FCMs and their affiliated participating B/Ds which may also be FCMs (together "participating clearing firms").

Section 5a(12) of the Act provides that the Commission shall approve contract market rules only if such rules "are determined by the Commission not to be in violation of (the) Act or the regulations of the Commission." Commingling of futures and non-futures funds of customers currently is not

permitted under the Commission's regulations. Section 4d(2) of the Act, 7 U.S.C. 6d(2), however, authorizes the Commission to issue an order prescribing the terms and conditions under which "money, securities, and property (received by an FCM to margin, guarantee, or secure the commodity futures trades or contracts of a customer) may be commingled * * * with any other money, securities, and property received by such (FCM) and required by the Commission to be separately accounted for and treated and dealt with as belonging to the customers of such (FCM)." Accordingly, any proposal which would permit such commingling would require Commission action pursuant to section 4d(2) of the Act, as well as section 5a(12).

Whereas, The ICC–OCC non-proprietary cross-margining proposal provides for calculation by the participating clearing organizations of a single margin requirement to support the positions of participating market professionals in eligible contracts carried by participating clearing firms in each non-proprietary cross-margining account;

Whereas, The Commission has reviewed the ICC–OCC cross-margining proposal, the proposed amendments to ICC's Margin Resolution and rules 101, 503, 513, 616, and 618, the proposed agreement between the participating clearing organizations, and the proposed agreements among the participating market professionals, the participating clearing firms, and the participating clearing organizations submitted by letter dated March 14, 1990, the amendments thereto through November 24, 1991, the representations of the participating clearing organizations as to the operation of the program, the representations of the Securities Investor Protection Corporation ("SIPC") and the Securities and Exchange Commission ("SEC"), and such other documents as constitute the complete record in this matter ("Record");

Whereas, The agreements among participating market professionals, participating clearing firms, and participating clearing organizations require that:

(a) Each participating market professional acknowledge in writing that any money, securities, and property, including securities option positions, held on his behalf in a non-proprietary cross-margining account ("cross-margining property") will be treated in a manner consistent with the terms of this Order and any other applicable order issued by the Commission;

(b) Each participating market professional acknowledge and agree in writing that any cross-margining property held on his behalf by a participating FCM or a participating B/D affiliated with a participating FCM will be customer property deemed to be received by the participating FCM to be accounted for, treated, and dealt with by such FCM as belonging to such market professional in a manner consistent with section 4d of the Act;

(c) Each participating market professional agree in writing that, in the event of the bankruptcy, liquidation, or receivership of or other proceeding involving the distribution of funds held by a participating clearing firm against which such market professional has a customer net equity claim in respect of cross-margining property, such claim shall be subordinated to the customer net equity claims of "public customers," as that term is defined in Commission Regulation 190.01(hh), 17 CFR 190.01(hh), of such clearing firm that do not relate to money, securities, or property in any cross-margining account; and

(d) Each participating market professional acknowledge and agree in writing that cross-margining property held for or on his behalf will not be customer property under the Federal securities laws to the extent necessary to effect this Order and will not be customer property under subchapter III of chapter 7 of title 11 of the Bankruptcy Code, 11 U.S.C. 741–752 or the Securities Investor Protection Act ("SIPA"), 15 U.S.C. 78aaa *et seq.*, and will not be claimed as such, and will be customer property under the Act, subchapter IV of chapter 7 of title 11 of the Bankruptcy Code, 11 U.S.C. 761–766, and part 190 of the Commission's regulations, 17 CFR part 190;

Whereas, Each participating market professional which signed such a participant agreement will be a customer of a participating FCM;

Whereas, Each participating clearing firm will treat money, securities, and property received in respect of all accounts other than cross-margining accounts in a manner consistent with the requirements of the Commission and the SEC appropriate thereto; and

Whereas, SIPC has represented that it has no objection to the agreements under which a participating market professional's cross-margining property would not be deemed to be customer property for purposes of SIPA; and

Whereas, The SEC has concurred with the treatment of securities positions and cross-margining accounts set forth in this Order;

Now Therefore, Based on the Record in this matter, and provided that the cross-margining proposal and related proposed rule amendments submitted by ICC are implemented consistently with the representations and agreements cited herein, and provided that:

(a) Each participating clearing organization, participating clearing firm, and participating market professional execute the agreements referred to herein;

(b) Each participating clearing organization, participating clearing firm, and depository separately account for cross-margining property maintained in non-proprietary cross-margining accounts and not commingle such cross-margining property with money, securities, and property maintained in any non-cross-margining accounts or proprietary cross-margining accounts;

(c) Each participating clearing organization, participating clearing firm, participating market professional, and depository provide the Commission with access to its books and records with respect to non-proprietary cross-margining accounts and positions in a manner consistent with Commission Regulation 1.31, 17 CFR 1.31; and

(d) Each participating clearing firm include all cross-margining property received from participating market professionals as provided herein to margin, guarantee, or secure commodity futures trades, commodity futures contracts, commodity option transactions, or securities option transactions, or accruing to such participating market professionals as a result of such trades, contracts, commodity option transactions, or securities option transactions, when calculating segregation requirements for purposes of section 4d of the Act;

(e) Each participating clearing firm compute total segregation requirements under section 4d of the Act and Commission Regulation 1.32, 17 CFR 1.32, by calculating separately the requirements for cross-margining and non-cross-margining accounts without using any net liquidating equity in one account to reduce a deficit in the other;

(f) Each participating clearing firm designate non-proprietary cross-margining accounts and positions as such in its books and records, including both internal documents maintained at the firms and account statements sent to participating market professionals;

(g) Each participating clearing organization calculate the margin requirements for each non-proprietary cross-margining account separately from the margin requirements for other accounts, including proprietary cross-margining accounts; collect any margin required with respect to non-proprietary

cross-margining accounts separately without applying any margin in any such account to satisfy a margin requirement in any proprietary account or any non-cross-margining customer account and without applying any margin in a non-cross-margining customer account to satisfy a margin requirement in any proprietary account or any non-proprietary cross-margining account; and maintain all cross-margining property received from participating clearing firms to margin, guarantee, or secure commodity futures trades, commodity futures contracts, commodity option transactions, or securities option transactions that are effected for non-proprietary cross-margining accounts or held in such accounts, and all accruals resulting from such trades, contracts, commodity option transactions, or securities option transactions, separately from money, securities, and property received to margin, guarantee, or secure commodity futures trades, commodity futures contracts, commodity option transactions, or securities option transactions that are effected for or held in any proprietary account or any non-cross-margining customer account, and related accruals; and

(h) Each participating clearing organization satisfy any deficiency in a non-proprietary cross-margining account without recourse to non-cross-margining segregated funds;

(i) Notwithstanding the foregoing, a participating clearing firm may commingle cross-margining property maintained in respect of the non-proprietary cross-margining arrangement between OCC and ICC with money, securities, and property maintained in respect of similar non-proprietary cross-margining arrangements between OCC and other commodity clearing organizations or between ICC and other commodity clearing organizations approved by the Commission, and may apply such commingled money, securities, and property to meet its obligations to a commodity or option clearing organization arising from trades or positions held in its non-proprietary cross-margining account established pursuant to one or more of such cross-margining account established pursuant to one or more of such cross-margining arrangements, provided that the participating clearing firm:

(i) Separately identify and account for the money, securities, and property held pursuant to each of the non-proprietary cross-margining arrangements; and

(ii) separately calculate the margin requirements with respect to each of the non-proprietary cross-margining arrangements, treating each position as being held pursuant to only one such arrangement;

It is hereby ordered, Pursuant to section 4d(2) of the Act:

(1) That all money, securities, and property received by a participating FCM or a participating B/D affiliated with a participating FCM to margin, guarantee, or secure securities option trades or contracts carried in a non-proprietary cross-margining account for or on behalf of participating market professionals, or accruing as a result of such trades or contracts, and held subject to the terms of this Order, shall be deemed to have been received by the participating FCM and shall be accounted for and treated and dealt with as belonging to the participating market professional customers of the participating FCM consistently with Section 4d of the Act;

(2) That, subject to the terms of this Order, notwithstanding any provision to the contrary in the Commission's regulations (including, but not limited to, Regulations 1.20(a), 1.22, and 1.24, 17 CFR 1.20(a), 1.22 and 1.24), the money, securities, and property described in the preceding paragraph of this Order may be commingled in a non-proprietary cross-margining account with money, securities, and property received by a participating FCM to margin, guarantee, or secure trades or positions in eligible commodity futures or commodity option contracts, or accruing as a result of such trades or contracts, and otherwise required by the Commission to be segregated under the Act; and

(3) That, in the event of the bankruptcy, liquidation, or receivership of or other proceeding involving the distribution of funds held by a participating clearing firm, any customer net equity claim which a participating market professional has in respect of cross-margining property held by such participating clearing firm in a non-proprietary cross-margining account shall be treated as a customer net equity claim, under part 190 of the Commission's regulations and subchapter IV of chapter 7 of title 11 of the Bankruptcy Code, but shall be subordinated to the customer net equity claims of "public customers," as that term is defined in Commission Regulation 190.01(hh), of such clearing firm that do not relate to cross-margining property.

It is further ordered, Pursuant to section 5a(12) of the Act and based upon the Commission action in the three preceding paragraphs of this Order, that the ICC's request for Commission approval of its proposal to expand its cross-margining program with OCC to include the cross-exchange net margining of the positions of certain market professionals and related proposed rule amendments is hereby granted.

Issued in Washington, DC, this 26th day of November, 1991.

By the Commission.

Jean A. Webb,

Secretary of the Commission.

[FR Doc. 91-28862 Filed 12-2-91; 8:45 am]

BILLING CODE 6351-01-M

DEPARTMENT OF DEFENSE

Office of the Secretary

Contract Administration Working Group of the DOD Advisory Panel on Streamlining and Codifying Acquisition Laws

AGENCY: Defense Systems Management College, DoD.

ACTION: Request for public comment.

SUMMARY: The DOD Advisory Panel has designated working groups of the Panel to address specified areas of acquisition laws. One working group is addressing laws relating to contract administration. The Panel and this working group have completed a preliminary collation and review of laws relating to administration of DOD contracts and will consider them in the following groupings and order of priority:

Contract payment, including progress payments, the Prompt Payment Act, and deferred payment.
Cost principles.
Contract audit and access to records.
Cost Accounting Standards.
Administration of contract provisions relating to price, delivery, and product quality.
Claims and disputes.
Extraordinary contractual relief—Public Law 85-804.

Set out below are the laws identified by the panel that relate to contract payment. Comments are sought as to whether they are serving their intended purpose. Have the laws created inefficiencies, have they unduly burdened the buyer/seller relationship, are they required for the continuing financial and ethical integrity of defense procurement programs, and are they required to protect the best interests of DOD?

Of interest to the Panel would be comments as to whether the laws are still relevant, do they overlap, duplicate, or conflict with other laws: Further, do they contain ambiguous terms or provisions which have led to problems in interpretation?

Finally, the Panel seeks comments on whether there are other laws, in addition to those listed below, relating to payment on DoD contracts, that should be considered by the Panel.

10 U.S.C. 2307 Advance payments.
10 U.S.C. 2355 Contracts: Vouchering procedures.
10 U.S.C. 2396 Advances for payments for compliance with foreign laws, rent in foreign countries, tuition, and pay and supplies of armed forces of friendly foreign countries.
10 U.S.C. 2410a Appropriated funds: Availability for certain contracts for 12 months.
10 U.S.C. 7312 Repair or maintenance of naval vessels: Progress payments under certain contracts.
10 U.S.C. 7313 Ship overload work: Availability of appropriations for unusual cost overruns and for changes in scope of work.
10 U.S.C. 7364 Advancement of funds for salvage operations.
10 U.S.C. 7521 Progress payment for work done; lien based on payment.
10 U.S.C. 7522b re Contract for research.
10 U.S.C. 7523 Tolls and fares: Payment or reimbursement.
31 U.S.C. 1341 Limitations on expending and obligating amounts.
31 U.S.C. 3324 Advances.
Title 31, Chapter 39—Prompt Payment.
41 U.S.C. 255 Advance or other payments.
41 U.S.C. 352 Violations (re service contracts).
P.L. 101-510 831 Mentor-Protege Pilot Program (also in note following 10 U.S.C. 2301).

Individuals and organizations wishing to provide information to the Working Group may provide the information to Ms. Joanne Barreca, Acquisition Law Task Force Member, at Defense Systems Management College, 8580 Cinderbed, suite 800, Newington, VA 22122 (703-355-2666.)

Dated: November 27, 1991.

L.M. Bynum,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 91-28938 Filed 12-2-91; 8:45 am]

BILLING CODE 3810-01-M

Privacy Act of 1974; Addition of a Record Systems Notice

AGENCY: Office of the Secretary of Defense (OSD).

ACTION: Addition of a record systems notice.

SUMMARY: The Office of the Secretary of Defense proposes to add a new record system to its inventory of record systems subject to the Privacy Act of 1974, as amended, (5 U.S.C. 552a).

DATES: The proposed action will be effective without further notice on January 2, 1992, unless comments are received that would result in a contrary determination.

ADDRESSES: Mr. Dan Cragg, OSD Privacy Act Officer, OSD Records Management and Privacy Act Branch, room 5C315, Pentagon, Washington, DC 20301-1155. Telephone (703) 695-0970.

SUPPLEMENTARY INFORMATION: The Office of the Secretary of Defense record system notices subject to the Privacy Act of 1974, as amended, (5 U.S.C. 552a) have been published in the **Federal Register** as follows:

50 FR 22090, May 29, 1985 (DoD Compilation, changes follow)
50 FR 47087, Nov. 14, 1985
51 FR 11807, April 7, 1986
51 FR 17508, May 13, 1986
51 FR 44668, Dec. 11, 1986
52 FR 2334, Jun. 19, 1987
53 FR 15868, May 4, 1988
3 FR 27894, Jul. 25, 1988
54 FR 33756, Aug. 16, 1989
54 FR 44314, Oct. 24, 1989
55 FR 17655, Apr. 26, 1990
55 FR 20180, May 15, 1990
55 FR 21429, May 24, 1990
55 FR 35449, Aug. 30, 1990
55 FR 49405, Nov. 28, 1990
56 FR 4604, Feb. 5, 1991
56 FR 9348, Mar. 6, 1991
56 FR 10545, Mar. 13, 1991

The new system report, as required by 5 U.S.C. 552a(r) of the Privacy Act was submitted on November 18, 1991, to the Committee on Government Operations of the House of Representatives, the Committee on Governmental Affairs of the Senate, and the Office of Management and Budget (OMB), pursuant to paragraph 4b of appendix I to OMB Circular No. A-130, "Federal Agency Responsibilities for Maintaining Records About Individuals," dated December 12, 1985 (50 FR 52738, December 24, 1985).

Dated: November 27, 1991.

L.M. Bynum,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

DUSDP 07

SYSTEM NAME:

PERSEREC Espionage Database.

SYSTEM LOCATION:

Records in the system are located at Defense Personnel Security Research & Education Center, 99 Pacific Street, Building 155, Monterey, CA 93940-2481.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

Individuals who have been arrested and convicted of espionage; those who have been prosecuted for espionage who committed suicide before trial or sentencing; and those who were not prosecuted for espionage because of death, suicide, or defection.

CATEGORIES OF RECORDS IN THE SYSTEM:

Background information including individual's name, Social Security Number, date of birth, city/state/ country of birth, education, marital status, gender, race, civilian or military member, rank (if military), security clearance (if applicable), years of federal service (if applicable), occupational category, job organization and location, age began espionage, first espionage contact, whether volunteered or recruited, receiving country, payment (if any), foreign relatives (if any), motivation, substance abuse (if applicable), date of arrest, arresting agency, date of sentence, sentence, and duration of espionage. Sources for records are newspaper and magazine articles, the biographies of spies, and similar open source works are included in paper files.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

5 U.S.C. 301; Executive Order 9397; DoDD 5210.79, "Defense Personnel Security Research and Education Center"; and ASD(C³I) 31 October 1991 memo, Subject: Request for Exemption from DoD Directive 5200.27.

PURPOSES:

To analyze factors which may contribute to acts of espionage and assemble a body of knowledge useful to improved personnel security procedures. This information will permit examination of espionage trends and will help identify personal and situational variables of interest to policy-makers and others concerned with personnel security issues.

Aggregate statistics will be reported to DoD and other Government agencies in a technical report prepared from open-sources and containing some illustrative material mentioning some of the more famous cases by name.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND THE PURPOSES OF SUCH USES.

The "Blanket Routine Uses" set forth at the beginning of the OSD's compilation of records system notices apply to this system.

POLICIES AND PRACTICES FOR STORING, RETRIEVING, RETAINING, AND DISPOSING OF RECORDS IN THE SYSTEM:

STORAGE:

Maintained on paper, computer and computer output products, and in microform.

RETRIEVABILITY:

Records may be retrieved by name and Social Security Number.

SAFEGUARDS:

Records are stored under lock and key in secure containers, and in a computer system with intrusion safeguards.

RETENTION AND DISPOSAL:

Analyses and research reports are permanent and will be transferred to the National Archives after 25 years; unneeded records will be shredded, erased or degaussed when no longer required for the project.

SYSTEM MANAGER AND ADDRESS:

Director, Defense Personnel Security Research and Education Center, 99 Pacific Street, Building 455E, Monterey, CA 93940–2481.

NOTIFICATION PROCEDURES:

Individuals seeking to determine whether this system of records contains information about themselves should address written inquiries to Director, Defense Personnel Security Research and Education Center, 99 Pacific Street, Building 455E, Monterey, CA 93940–2481.

The inquiry should include full name and Social Security Number.

RECORD ACCESS PROCEDURES:

Individuals seeking access to records about themselves contained in this system of records should address a written request to Director, Defense Personnel Security Research and Education Center, 99 Pacific Street, Building 455E, Monterey, CA 93940–2481.

The inquiry must include name and Social Security Number.

CONTESTING RECORDS PROCEDURES:

The Office of the Secretary of Defense rules for accessing records and for contesting contents and appealing initial OSD determinations are published in OSD Administrative Instruction No. 81, "OSD Privacy Program"; 32 CFR part 311; or may be obtained from the system manager.

RECORD SOURCE CATEGORIES:

Information is obtained from newspaper and magazine articles and similar open source documents.

EXEMPTIONS CLAIMED FOR THE SYSTEM:

None.

[FR Doc. 91-28936 Filed 12-2-91; 8:45 am]
BILLING CODE 3810-01-M

DEPARTMENT OF DEFENSE

Corps of Engineers, Department of the Army

Construction Productivity Advancement Research (CPAR) Program

AGENCY: Corps of Engineers, Department of the Army, DOD.

ACTION: Notice of availability.

SUMMARY: The purpose of this notice is to inform potential applicants of a program of cost-shared research, development and technology transfer (R&D) projects between the U.S. Army Corps of Engineers (Corps) and the U.S. construction industry. The purpose of the Construction Productivity Advancement Research (CPAR) Program is to assist the U.S. construction industry in enhancing its productivity and domestic and international competitive position through the development and reduction-to-practice of advanced technologies, materials and construction management systems.

DATES: Effective date is December 2, 1991. Proposals will be accepted until February 28, 1992.

ADDRESSES: Proposals for the Fiscal Year 1992 CPAR Program should be submitted to the Corps laboratories identified in the CPAR Guidelines for Participation, dated December 1991. Copies of the *Guidelines* may be obtained by writing to: HQUSACE, Attn: CERD–C; 20 Massachusetts Avenue, NW.; Washington, DC 20314–1000, or by calling (202) 272–0257.

FOR FURTHER INFORMATION CONTACT: Mr. Jesse A. Pfeiffer, Jr., P.E.; HQUSACE, CERD–C; 20 Massachusetts Avenue, NW.; Washington, DC 20314–1000, or call (202) 272–1846 or 272–0257.

SUPPLEMENTARY INFORMATION: CPAR is a cost-shared partnership between the Corps, the U.S. construction industry (contractors, equipment and material suppliers, architects, engineers, financial organizations), public and private foundations, non-profit organizations, academic institutions, state and local governments and other entities who are interested in enhancing construction productivity and competitiveness. CPAR was created to help the domestic construction industry improve productivity and regain its competitive edge nationally and internationally by building on the foundation of the existing Corps Construction R&D Program and laboratory resources through an expansion and leveraging effect that cost-shared partnerships provide. The objective of CPAR is to facilitate research, development and application of advanced technologies through cooperative R&D, field demonstration, licensing agreements and other means of Commercialization, technology transfer and reduction-to-practice. Advancing the productivity and competitiveness of the U.S. construction industry will provide savings in construction costs for the Government and U.S. industries, and result in a boost to the U.S. economy in general. R&D efforts conducted under CPAR will be based on proposals received from U.S. construction industry entities and others, as noted above, which can be addressed effectively by a partnership and which will benefit both the Corps and the construction industry.

Participation in CPAR is open to any U.S. private firms, including corporations, partnerships, limited partnerships and industrial development organizations; public and private foundations; academic institutions; non-profit organizations; units of State and local governments; and others who have an interest in and the capability to address CPAR objectives. As provided by law, special consideration will be given to small business firms and consortia involving small business firms. Preference will be given to business units located in the United States that agree to substantially manufacture and apply the products in the United States. Consideration will be given to a potential partner that is subject to the control of a foreign company or government if that foreign government permits the U.S. agencies, organizations, or other persons to enter into cooperative research and development agreements and licensing agreements.

The cost of each CPAR project will be shared by the Corps and the construction industry partner(s). Specific cost-sharing terms will be defined for each proposed project prior to submission of the proposal to Corps Headquarters (HQUSACE) for approval. "In-kind" services and/or use of facilities may be considered in arriving at a cost-sharing agreement. As required by law, not more than fifty (50) percent of the total cost of a CPAR project will be provided by the Corps and not less than five (5) percent of the construction industry partner's share of the cost must be contributed in cash. The Corps and the U.S. construction industry partner(s)

may each contribute personnel, services, facilities, property, patent licenses (or assignment or options to the patent license) and money. No costs previously incurred by the Corps or the construction industry partner(s) on the subject matter of the CPAR project may be recovered in the cost-sharing agreement.

A CPAR Cooperative Research and Development Agreement (CPAR-CRDA) specific to each project will be negotiated between the Corps and the U.S. construction industry partner(s). The CPAR-CRDA is defined by law as neither a procurement contract nor an assistance agreement (grant or cooperative agreement). The CPAR-CRDA will contain, in addition to the cost-sharing terms, all other conditions and responsibilities necessary to complete the project and commercialize/transfer the technology, including rights to inventions. It is anticipated that one of the most effective ways of assuring the new technology is disseminated to the public is to provide the U.S. construction industry partner(s) with a proprietary "ownership" interest in the new technology. Therefore, to the extent permitted by law, the Corps will generally grant to the industry partner(s) an option to licenses or assignments for any intellectual property made in whole or in part by a Federal employee under the CPAR-CRDA, retaining a non-transferable, irrevocable, paid-up license to practice the invention or have the invention practiced throughout the world on behalf of the Government. The Corps may, without further notice to others, agree to negotiate an exclusive license or waive title to intellectual property if such actions would facilitate commercialization and use of the technology. To the greatest extent possible and appropriate, licensing and assignments will be on a non-exclusive basis. In some cases, where appropriate, royalties will be negotiated and collected by the Government in exchange for such licenses or assignments.

CPAR is designed to promote and assist in the advancement of ideas and technology which will have a direct, positive impact on construction productivity and Corps mission accomplishment. CPAR is focused on four major areas: planning and design improvement, improved construction site productivity, advanced materials, and innovative methods to commercialize and transfer R&D products to the construction industry. However, any idea for improving construction productivity will be considered. Ideas that cannot define a direct and demonstrable link to the advancement of construction productivity will not be accepted into the CPAR Program. Areas of interest include, but are not limited to:

Planning and Design Improvement

- Total Integrated Design Systems.
- Computer-Aided Planning and Engineering Tools.
- Computer-Aided Design Systems.
- Advanced Site Investigation Technology.
- Knowledge-Based Cost Estimating Systems.
- Expert Systems/Artificial Intelligence.
- Materials Selection Systems.
- Advanced Technology Selection Systems.

Improved Construction Site Productivity

- Computer-Aided Construction Management Systems.
- Automated Construction/Robotics.
- Automated Inspection and Quality Control.
- Advanced Excavating and Tunneling.

Marine Construction

- Cold Weather Construction.
- Construction Management Methods.
- Expert Systems.
- Materials Handling.

Advanced Materials

- High-Performance Cementitious Materials.
- Structural Polymers.
- Advanced Ceramics.
- Metal Matrix Composites.
- Advanced Fabrication Systems.
- Coatings. Adhesives/Fasteners.
- Geomodifiers/Geotextiles.

Commercialization/Technology Transfer Innovation

- User-Based Technology Transfer Processes.
- Technical Support Services.
- Skills Upgrading Methods.
- Information Exchange Systems.

Proposal Review Process

Proposals received by the Corps laboratories which meet CPAR criteria may be discussed and further developed, as necessary, by the laboratory and construction industry partner(s). The following criteria will be used to evaluate the proposals. The first two evaluation factors are of equal importance and are more significant than the remaining factors, which are listed in descending order of importance:

1. *Potential Impact On U.S. Construction Industry Productivity*

High—Technological advancement which would have major beneficial impact on current construction industry processes, materials and/or equipment and will have a demonstrable major beneficial impact on construction industry productivity and effectiveness.

Medium—Technological advancement which would improve on and/or demonstrate currently available processes, materials and/or equipment not in wide-spread construction industry use and which would have a demonstrable beneficial impact on construction industry productivity and effectiveness.

Low—Technological advancement which would upgrade construction industry processes, materials and/or equipment in current use and which would have a limited but beneficial impact on construction industry productivity and effectiveness.

2. *Potential Impact on the Corps of Engineers*

High—Technological advancement which would be a major improvement in technology and procedures currently used by the Crops and which would have a demonstrable major beneficial impact on the Corps.

Medium—Technological advancement which would significantly improve currently used Corps technology and procedures and which would result in demonstrable benefits for the Corps.

Low—Technological innovation which would upgrade current Corps standard technology and procedures and which would have a limited but beneficial impact on the Crops.

3. *Commercialization/Technology Transfer*

High—Plan/concepts stated for broad-scale use/adoption of the product by non-Federal and Federal organizations and the production/marketing/dissemination of the product by the non-Federal partner(s).

Medium—Plans/concepts stated for some beneficial use/adoption of the product by non-Federal and Federal organizations.

Low—Plans/concepts stated for limited but beneficial use/adoption of the product by non-Federal and Federal organizations.

4. *Ease of Adoption*

High—Technology provides construction industry productivity and effectiveness improvement with minimal equipment, training, materials and operating costs beyond the cost of current practice.

Medium—Technology provides construction industry productivity and

effectiveness improvements, but requires moderate additional equipment, training, materials, and operating costs beyond the cost of current practice.

5. *Probability of Achieving Projected Productivity and Effectiveness Enhancement*

High—Some risk, requires innovative application of current knowledge, high probability of success.

Medium—Moderate risk, concepts exist but are unproven, good probability of success.

Low—High risk, basic concepts must be developed and proven, uncertain probability of success.

6. *Project Duration*

High—Project, including demonstration of benefits, can be completed in 3 years or less. Medium—Project, including demonstration of benefits, can be completed in 4 years or less.

Low—Project, including demonstration of benefits, will require more than 4 years to complete.

7. *R&D Investment*

High—Project will obligate the Corps to invest less than $300,000 per year.

Medium—Project will obligate the Corps to invest between $300,000 and $500,000 per year.

Low—Project will obligate the Corps to invest more than $500,000 per year.

After discussions between the laboratory and the construction industry partner(s), a CPAR Executive Summary of the proposal will be prepared by the laboratory. The Executive Summary will contain all expected costs and costsharing arrangements, time needed to complete, specific end product(s), proposed commercialization/technology transfer plan, and expected benefits to the U.S. construction industry and the Corps.

Corps laboratories will submit their recommended Executive Summaries to HQUSACE for consideration under the CPAR Program. The CPAR Executive Summaries will be reviewed and recommendations made by the CPAR Executive Committee in HQUSACE. The CPAR Executive Committee is composed of senior-level HQUSACE managers. The Director of Civil Works, HQUSACE, will act on the recommendations of the Executive Committee in approving the annual CPAR program.

All information and data furnished by the potential construction industry partner(s) will be used for evaluation purposes only and will be safeguarded from unauthorized disclosure in accordance with applicable laws. Protection of information during and after completion of a CPAR project will be defined and agreed to in the CPAR-CRDA. Classified information and data will be handled in accordance with Army regulations.

Additional Requirements

Applicants are reminded that a false statement may be grounds for denial or termination of funds and grounds for possible punishment by a fine or imprisonment. Except where declared by law or approved by the head of agency, no award of Federal funds shall be made to an applicant who is delinquent on a Federal debt until the delinquent account is made current or satisfactory arrangements are made between affected agencies and the debtor. No award will be made to a debarred or suspended firm or organization.

Classification

This document is not a major rule requiring a regulatory analysis under Executive Order 12291 because it will not have an annual impact on the economy of $100 million or more, nor will it result in a major increase in costs or prices for any group, nor have a significant adverse effect on competition, employment, investment, productivity, innovation, or on the ability of U.S.-based enterprises to compete with foreign-based enterprises in domestic or export markets. It is not a major Federal action requiring an environmental assessment under the National Environment Policy Act. The CPAR Program does not involve the mandatory payment of any matching funds from a State or local government, and does not affect directly any State or local government. Accordingly, the Corps determined that Executive Order 12372 is not applicable to CPAR. This notice does not contain policies with Federalism implications sufficient to warrant preparation of a Federalism assessment under Executive Order 12612. CPAR is being carried out under the authority of section 7, Water Resources Development Act of 1988 (Pub. L. 100–676) (33 U.S.C. 2313).

Dated: November 14, 1991.

Dennis C. Cochrane,

Colonel, General Staff; Executive, OASA(CW).

[FR Doc. 91- 28940 Filed 12–2–91; 8:45 am]

BILLING CODE 3710–08–M

Intent To Prepare a Joint Draft Environmental Impact Statement/Environmental Impact Report (EIS/EIR) for the Port of Los Angeles Deep-Draft Navigation Feasibility Study, Los Angeles and Long Beach, CA

AGENCY: U.S. Army Corps of Engineers, Los Angeles District (Federal); Port of Los Angeles (State).

ACTION: Notice of intent to prepare a joint draft environmental impact statement/environmental impact report (EIS/EIR).

SUMMARY: The Proposed Project involves the dredging of navigation channels and turning basins in Los Angeles Harbor, California, and the placement of the dredged material in the harbor creating about 582 acres of new landfill to support new terminals and associated handling and storage facilities. This Proposed Project comprises a portion of the Ports of Los Angeles (POLA) and Long Beach (POLB) 2020 Master Plan. The Ports' 2020 Master Plan represents a long-range, comprehensive concept for planned development of approximately 2400 acres of new landfill within the Los Angeles-Long Beach Harbors. The first phase of the 2020 Plan includes six (6) dredge and fill increments. Four of these (Increments 2, 3, 4, and 5) comprise the proposed Project and would be implemented in the POLA, by the U.S. Army Corps of Engineers (Corps) and POLA in partnership. The two remaining (Increments 1 and 6) are associated with the POLB; however, the POLB has decided not to participate in the Proposed Project and plans to proceed with POLB development without Federal financial assistance. Therefore, the two POLB increments are not part of the Proposed Project, but will be considered in the cumulative impacts analyses.

The primary purpose of the EIS/EIR is to assess the potential environmental impacts associated with the proposed navigation improvements, the 582 acres of new landfill, and potential mitigation measures. The Corps will serve as the Federal Lead Agency consistent with the National Environmental Policy Act (NEPA). The Port of Los Angeles is the non-Federal sponsor of the Deep-Draft Navigation Feasibility Study and will serve as the State Lead Agency consistent with the California Environmental Quality Act (CEQA).

FOR FURTHER INFORMATION CONTACT: Colonel Charles S. Thomas, Attn: Mr. Frank Piccola, Environmental Resources Branch, U.S. Army Corps of Engineers, 300 North Los Angeles Street, Los Angeles, California 90012-2325, (213) 894-0244.

SUPPLEMENTARY INFORMATION:

1. Proposed Action

The primary purpose of the proposed deep-draft navigation project is the modification of existing navigation channels and turning basins, the creation of new navigation channels to existing lands, and to provide navigation improvements needed to meet existing and estimate demands on the port facilities consistent with the 2020 Master Plan. The Port of Long Beach has withdrawn as a participant in the proposed Federal project, but continues to support the 2020 Master Plan.

The Proposed Project would require dredging in San Pedro Bay and placement of the dredged material in the Los Angeles Harbor to create approximately 582 acres of new landfill. The dredge and fill project for channels and creation of new lands would be constructed in four (4) increments through the year 2005. The project scope also includes the public agency actions required to amend local plans and to comply with state and Federal law and environmental regulatory programs. The 582 acres of landfill would require specific approval by the Corps.

2. Study Alternatives

The EIS/EIR will address various alternatives in addition to the Proposed Project, including but not limited to the following:

A. No Action

This alternative assumes that no channel improvements or landfill improvements will be made within the harbor. It also assumes that all existing terminals and new terminals developed on existing undeveloped Port lands will be operating at Maximum Practicable Capacity (MPC). Cargo handling capacity would be maximized at existing terminals and the use of existing land would be optimized. When the MPC of the Port has been reached, the remaining capacity would be diverted to other west coast ports.

B. Inland Expansion

This alternative assumes that construction of certain terminal facilities inland from the existing port area would occur when the MPC of the POLA is exceeded.

C. Expansion Outside the Breakwater

This alternative assumes construction of new channels and landfills outside the protected waters of the harbor. New facilities required due to the exceedance of the MPC would occur on these landfills.

D. Expansion of Other Ports

This alternative assumes the diversion of cargo from the POLA to other west coast ports. Based on the types and destination of cargo, expansion of these west coast ports may also be necessary to accommodate the increase in throughput.

E. Dredge Only

This alternative assumes deepening of existing navigation channels and harbor areas to provide channel depths and turning basins necessary to serve existing terminals and underutilized, existing lands which would be developed for terminal use. Disposal of the dredged material would involve either disposal via nearby beach replenishment or an ocean disposal site, rather than at the proposed landfill locations within the harbor.

F. Reduced Dredge and Landfill

This alternative assumes that navigation channels would be dredged in three (3) construction increments and the resultant dredged material would be utilized to construct approximately 228 acres of new landfill. The remaining quantity of dredged material would be disposed of at an approved offshore site. The new landfill areas and deepened channels would accommodate a portion of the forecasted future cargo growth, but not all.

3. Scoping Process

The purpose of this Notice is to advise interested persons of recent changes in the scope of effort; not to reinitiate the process or solicit new comment. One significant change in project scope since the release of the Preliminary Draft Environmental Impact Statement/Report (PDEIS/EIR) has been the withdrawal of the Port of Long Beach from participation in the Proposed Project. Another change, based on comments received during the public review period for the PDEIS/EIR, is the reduced scope of the Proposed Project itself, resulting in the proposed dredging and filling of 582 acres rather than 1400 acres as previously pursued. If approved, this would allow for meeting current and estimated demands consistent with the 2020 Master Plan and the EIS/EIR would provide a basis for future related port expansion and subsequent NEPA and CEQA analyses and documentation. Another Draft EIS/EIR will be released for public review and comment after these changes have been evaluated.

Potentially significant issues identified to date include impacts to air quality, oceanographic and water resources, geology and seismicity, public services and utilities, transportation and circulation, biological resources and endangered species, land and water use, recreation, energy, public health and safety, aesthetics including light and glare, noise, socioeconomic, and cultural resources. The pending Draft EIS/EIR will include the analysis of the above Proposed Project and alternatives; measures to avoid, minimize and/or mitigate for significant impacts which may result from project implementation; and the cumulative effects of the proposed action on the region.

Scoping meetings are not scheduled for this action. This action (NOI) is intended to supplement the original scoping process for the Feasibility Study and EIS/EIR initiated in 1986, the PDEIS/EIR (September 1990) Notice of Availability and public comment period, which serve to meet the requirements of NEPA and other pertinent environmental law. During the previous scoping/NEPA process, public and agency comments were received and reviewed. Those comments will be considered in the revised Draft EIS/EIR. This NOI does not serve as public notice for any section 404 permit actions.

An extensive mailing list is being developed which includes Federal, state, and local agencies and other interested public and private organizations and persons. Formal coordination with appropriate Federal, State, and local agencies will be conducted according to the requirements of NEPA and other applicable law.

4. Public Meeting(s)

A Public Meeting(s) will be held during the review period of the Draft EIS/EIR. Specific meeting date(s), time(s), and place(s) will be published in local newspapers and furnished to those on the mailing list.

5. Availability of the Draft EIS/EIR

The Draft EIS/EIR is expected to be available to the public in March 1992.

Dated: November 15, 1991.

Charles S. Thomas,

Colonel, Corps of Engineers, District Engineer.

[FR Doc. 91-28778 Filed 12-2-91; 8:45 am]

BILLING CODE 3710-KF-M

Defense Contract Audit Agency

Privacy Act of 1974; New Record System

AGENCY: Defense Contract Audit Agency, DOD.

ACTION: Addition of a system of records.

SUMMARY: The Defense Contract Audit Agency proposes to add a system of records subject to the Privacy Act of 1974, as amended (5 U.S.C. 552a). The record system notice for the new system is set forth below.

DATES: The proposed action will be effective without further notice on January 2, 1992, unless comments are received which would result in a contrary determination.

ADDRESSES: Send any comments to Mr. Dave Henshall, ATTN: CMR, Defense Contract Audit Agency, Cameron Station, Alexandria, VA 22304–6178. Telephone (202) 274–4400.

SUPPLEMENTARY INFORMATION: The Defense Contract Audit Agency systems of records, as prescribed by the Privacy Act of 1974 (5 U.S.C. 552a), have been published in the **Federal Register** as follows:

50 FR 22943, May 29, 1985 (DoD Compilation changes follow)
51 FR 18017, May 16, 1986
54 FR 37360, Sep. 8, 1989
54 FR 43316, Oct. 24, 1989
54 FR 46756, Nov. 7, 1989
55 FR 6818, Feb. 27, 1990
55 FR 21917, May 30, 1990
55 FR 36847, Sep. 7, 1990
55 FR 40004, Oct. 1, 1990
56 FR 23680, May 24, 1991
56 FR 46163, Sep. 10, 1991

A new system report, as required by 5 U.S.C. 522a(r) of the privacy Act, was submitted on November 20, 1991, to the Committee on Government Operations of the House of Representatives, the Committee on Governmental Affairs of the Senate, and the Office of Management and Budget (OMB) pursuant to paragraph 4b of appendix I to OMB Circular No. A-130, "Federal Agency Responsibilities for Maintaining Records About Individuals," dated December 12, 1985 (50 FR 52738, December 24, 1985).

Dated: November 27, 1991.

L.M. Bynum,

Alternate OSD Federal Register, Liaison Officer, Department of Defense.

RDCAA 201.01

SYSTEM NAME:

Individual Access Files.

SYSTEM LOCATION:

Headquarters, Defense Contract Audit Agency, Personnel and Security Division, Cameron Station, Alexandria, VA 22304–6178.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

DCAA personnel, contractor employees, and individuals granted or denied access to DCAA activities.

CATEGORIES OF RECORDS IN THE SYSTEM:

Documents relating to the request for authorization, issue, receipt, surrender, withdrawal and accountability pertaining to identification cards, to include application forms, photographs, and related papers.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

Section 21 of the Internal Security Act 1950 (50 U.S.C. 781, et seq.); Department of Defense Directives 5200.8 and 5105.36 which assign to the Director, DCAA the responsibility for protection of property and facilities under his control; and Executive Order 9397.

PURPOSE(S):

Information is maintained and used to adequately control access to and movement on DCAA activities.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND THE PURPOSES OF SUCH USES:

The "Blanket Routine Uses" that appear at the beginning of the DCAA's compilation of record system notices apply to this record system.

POLICIES AND PRACTICES FOR STORING, RETRIEVING, ACCESSING, RETAINING, AND DISPOSING OF RECORDS IN THE SYSTEM:

STORAGE:

Paper records in file folders, application cards, and index cards.

RETRIEVABILITY:

Retrieved alphabetically by name.

SAFEGUARDS:

Records are maintained in areas accessible only to authorized DCAA personnel.

RETENTION AND DISPOSAL:

Records are destroyed one year after termination or transfer of person granted access, except that individual identification cards and photographs will be destroyed upon revocation, expiration or cancellation.

SYSTEM MANAGER(S) AND ADDRESS(ES):

Headquarters, Defense Contract Audit Agency (DCAA), Personnel and Security Division, Cameron Station, Alexandria, VA 22304–6178.

NOTIFICATION PROCEDURE:

Individuals seeking to determine whether this system of records contains information about themselves should address written inquiries to Headquarters, Defense Contract Audit Agency (DCAA), Personnel and Security Division, Cameron Station, Alexandria, VA 22304–6178.

RECORD ACCESS PROCEDURES:

Individuals seeking access to records about themselves contained in this system of records should address written inquiries to Headquarters, Defense Contract Audit Agency (DCAA), Personnel and Security Division, Cameron Station, Alexandria, VA 22304–6178.

Written requests for information should contain the full name, current address and telephone numbers of the individual. For personal visits, the individual should be able to provide some acceptable identification, that is, driver's license, employing office identification card, and give some verbal information that could be verified with the file.

CONTESTING RECORD PROCEDURES:

The Defense Contract Audit Agency rules for contesting contents and appealing initial agency determinations are contained in DCAA 5410.10, DCAA Privacy Act Programs; 32 CFR part 317; or may be obtained from the system manager.

RECORD SOURCE CATEGORIES:

Individuals applying for identification cards and security personnel.

EXEMPTIONS CLAIMED FOR THE SYSTEM:

None.

[FR Doc. 91-28937 Filed 12-2-91; 8:45 am]
BILLING CODE 3810-01-M

Department of the Navy

Intent To Prepare a Programmatic Environmental Impact Statement for Disposal of Dredged Material From Related Navy Dredging Projects in San Diego Bay, San Diego, CA

Pursuant to section 102(2)(C) of the National Environmental Policy Act (NEPA) of 1969 as implemented by the Council on Environmental Quality regulations (40 CFR parts 1500–1508), the Department of the Navy announces its intent to prepare a Programmatic

Environmental Impact Statement (PEIS) for dredged material disposal related to future Navy dredging projects in San Diego Bay, San Diego, California.

This PEIS is being undertaken in response to inquiries from numerous federal, state, and local agencies regarding U.S. Navy plans for future dredging projects in San Diego Bay. The objectives of this project will be to:

(1) Identify candidate sites for future disposal of dredged material,

(2) Broadly assess the existing environments of these candidate sites and evaluate the environmental consequences of using them for disposal, and

(3) Develop a planning methodology to select candidate disposal sites after the material characteristics of a specific dredging project are known.

The completed PEIS document will comprise Tier I of a two-tiered NEPA process. Tier II environmental studies/documentation will be accomplished for future, individual dredging projects.

Eight tentative Navy dredging projects in San Diego Bay have been identified. The tentative projects are located at Naval Air Station North Island; Naval Amphibious Base, Coronado; Naval Supply Center Pier, San Diego; and Naval Station, San Diego.

Dredged material disposal alternatives being considered are open ocean disposal, in-bay disposal, upland disposal, and the no action alternative. Environmental impacts of the disposal of dredged material at these alternative locations shall be in the PEIS.

The Navy will hold a public scoping meeting on December 18, 1991, from 7:30–9 p.m., in the Blue Room of Southwest Division, Naval Facilities Engineering Command, 1220 Pacific Highway, San Diego, California. This meeting will be advertised in San Diego area newspapers.

A formal presentation will precede request for public comment. Navy representatives will be available at this meeting to receive comments from the public regarding issues of concern to the public.

It is important that federal, state, and local agencies and interested individuals take this opportunity to identify environmental concerns that should be addressed during the preparation of the PEIS.

Agencies and the public are also invited and encouraged to provide written comments in addition to, or in lieu of, oral comments at the public meeting. To be most helpful, scoping comments should clearly describe specific issues or topics which the commentor believes the PEIS should address. Written statements and/or questions regarding the scoping process should be mailed no later than 30 days from the date of this publication to Mr. Lowell Martin, code 232LM, telephone (619) 532–2991, Southwest Division, Naval Facilities Engineering Command, Building 127, 1220 Pacific Highway, San Diego, California 92132–5190.

Dated: November 27, 1991

Wayne T. Baucino,

LT, JAGC, USNR Alternate Federal Register Liaison Officer.

[FR Doc. 91–28898 Filed 12–2–91, 8:45 am]

BILLING CODE 3810-AE-M

Department of the Navy

Navy Resale System Advisory Committee; Closed Meeting

Pursuant to the provisions of the Federal Advisory Committee Act (5 U.S.C. app. 2), notice is hereby given that the Navy Resale System Advisory Committee will meet on December 6, 1991 in Philadelphia, Pennsylvania. Sessions of the meeting will commence at 8 a.m. and 8:15 a.m. The 8:15 a.m. to 4 p.m. session will be closed to the public because it is likely to relate solely to internal agency personnel rules and practices; may disclose trade secrets and commercial or financial information; and, may involve information which, if disclosed prematurely, would be likely to significantly frustrate implementation of a proposed agency action. The Secretary of the Navy has therefore determined that the 8:15 a.m. to 4 p.m. session of the meeting be closed to the public because it will be concerned with matters listed in section 552b(c)(2), (4), and (9)(B) of title 5, United States Code.

This Notice is being published late because of administrative delays which constitute an exceptional circumstance, not allowing Notice to be published in the **Federal Register** at least 15 days before the date of the meeting.

For further information concerning this meeting contact: Captain N. Malcom, SC, USN, Naval Supply Systems Command (Sup 09B), room 606, Crystal Mall, Building No. 3, Arlington, VA 22202, Telephone No. (703) 607-0072/3.

Dated: November 27, 1991.

Wayne T. Baucino,

Lieutenant, JAGC, U.S. Naval Reserve, Alternate Federal Register Liaison Officer.

[FR Doc. 91–28901 Filed 12–2–91, 8:45 am]

BILLING CODE 3810-AE-F

DEPARTMENT OF EDUCATION

Advisory Committee on Student Financial Assistance; Meeting

AGENCY: Advisory Committee on Student Financial Assistance, Education.

ACTION: Notice of closed meeting.

SUMMARY: This notice sets forth the schedule and proposed agenda of a forthcoming closed meeting of the Advisory Committee on Student Financial Assistance. This notice also describes the functions of the Committee. Notice of this meeting is required under section 10(a)(2) of the Federal Advisory Committee Act. This document is intended to notify the general public.

DATES AND TIMES: December 12, 1991 beginning at 8:30 a.m. and ending at 5 p.m.; and December 13, 1991 beginning at 8:30 a.m. and ending at 12 noon.

ADDRESSES: The Wyndham Bristol Hotel, William Penn Room, 2430 Pennsylvania Avenue, NW., Washington, DC 20037.

FOR FURTHER INFORMATION CONTACT: Dr. Brian K. Fitzgerald, Staff Director, Advisory Committee on Student Financial Assistance, room 4600, ROB–3, 7th & D Streets, SW., Washington, DC 20202–7582; (202) 708–7439.

SUPPLEMENTARY INFORMATION: The Advisory Committee on Student Financial Assistance is established under section 491 of the Higher Education Act of 1965 as amended by Public Law 100–50 (20 U.S.C. 1098). The Advisory Committee is established to provide advice and counsel to the Congress and the Secretary of Education on student financial aid matters, including providing technical expertise with regard to systems of need analysis and application forms, making recommendations that will result in the maintenance of access to postsecondary education for low- and middle-income students, and conducting a study of institutional lending in the Stafford Student Loan Program. The Congress has also directed the Advisory Committee to provide assistance in preparing for the reauthorization of the Higher Education Act.

The Advisory Committee will meet in Washington, DC from 8:30 a.m. to 5 p.m. on December 12; and from 8:30 a.m. to 12 noon on December 13.

The meeting will be closed to the public from 8:30 a.m. to 5 p.m. on December 12 and from 8:30 a.m. to 12 noon on December 13 to interview candidates for the senior staff position of Associate Director to the Advisory

Committee and to discuss other personnel matters. The proposed agenda includes (a) opening remarks; (b) an overview of the selection process; (c) interview of the candidates; and (d) discussion of the candidates. The ensuing discussion will disclose information of a personal nature where disclosure would constitute a clearly unwarranted invasion of personal privacy if conducted in open session, and such matters are protected by exemption (6) of section 552(c) of title 5 U.S.C. The meeting will be closed under the authority of section 10(d) of the Federal Advisory Committee Act (Public Law 92–463; 5 U.S.C., appendix 2) and under exemption (6) of section 552b(c) of the Government Sunshine Act (Public Law 94–409). A summary of the activities at the closed session and related matters which are informative to the public consistent with the policy of title 5 U.S.C. 552b will be available to the public within fourteen days of the meeting.

Records are kept of all Committee proceedings, and are available for public inspection at the Office of the Advisory Committee on Student Financial Assistance, room 4600, 7th and D Streets, SW., Washington, DC from the hours of 9 a.m. to 5:30 p.m., weekdays, except Federal holidays.

Brian K. Fitzgerald,

Staff Director, Advisory Committee on Student Financial Assistance.

[FR Doc. 91–28855 Filed 12–2–91; 8:45 am]

BILLING CODE 4000–01–M

DEPARTMENT OF ENERGY

Invention Available for License

AGENCY: Office of the General Counsel, Department of Energy.

ACTION: Notice of invention available for license.

SUMMARY: The Department of Energy hereby announces that U.S. Patent No. 4,834,497, entitled "Fiber Optic Fluid Detector" is available for license, in accordance with 35 U.S.C. 207–209. A copy of the patent may be obtained, for a modest fee, from the U.S. Patent and Trademark Office, Washington, DC 20231.

FOR FURTHER INFORMATION: Robert J. Marchick, Off of the Assistant General Counsel for Intellectual Property, U.S. Department of Energy, 1000 Independence Avenue, SW., Washington, DC 20585; Telephone (202) 586–2802.

SUPPLEMENTARY INFORMATION: 35 U.S.C. 207 authorizes licensing of Government-owned inventions. Implementing regulations are contained in 37 CFR part 404. 37 CFR 404.7(a)(1) authorizes exclusive licensing of Government-owned inventions under certain circumstances, provided that notice of the invention's availability for license has been announced in the **Federal Register**.

Issued in Washington, DC, on November 25, 1991.

John J. Easton, Jr.,

General Counsel.

[FR Doc. 91–28969 Filed 12–2–91; 8:45 am]

BILLING CODE 6450–01–M

Intent To Develop a Resource Allocation Support System for the Office of Waste Operations and Request for Public Comment

AGENCY: U.S. Department of Energy, Office of Environmental Restoration and Waste Management, Office of Waste Operations.

ACTION: Request for public comments on the development of a resource allocation support system for the Office of Environmental Restoration and Waste Management, Office of Waste Operations.

SUMMARY: The Department of Energy (DOE) is in the initial stages of developing a resource allocation support system to aid in budgetary decisions by the Office of Waste Operations (WO). The WO program manages wastes from DOE's processing, manufacturing, and research activities using appropriate treatment, storage, and disposal technologies. These wastes must be managed in a way that protects the health and safety of the public and workers and the quality of the environment. In addition, WO activities are being directed to achieve real reductions in the volume and toxicity of hazardous, mixed, radioactive, and sanitary wastes generated by DOE's activities.

Currently, funding allocation decisions for WO activities are aided through the use of a categorical system, which is described in the Five-Year Plan (DOE/S–0089P, August 1991, pp. 174–175). DOE is considering a resource allocation support system based on a formal decision-making methodology, namely, multiattribute utility analysis. It is intended that the new resource allocation support system be technically sound; responsive to public values, ideas, and concerns; and generally more helpful in aiding funding decisions than the current system. DOE requests comments on the WO objectives to be used by the system, and how the resource allocation support system should be structured.

DATES: Written comments should be postmarked by January 2, 1992 to assure consideration. Comments received after that date will be considered to the extent practicable.

ADDRESSES AND FURTHER INFORMATION: Comments and requests for additional information should be directed to: Kevin Donovan, EM–333, Trevion II, U.S. Department of Energy, Washington, DC 20585–0002; telephone number (301) 903–7671.

SUPPLEMENTARY INFORMATION: The resource allocation support system is expected to aid DOE managers in evaluating the benefits and costs of funding options at different WO budget levels. This system, a multiattribute utility process, should also help DOE managers examine tradeoffs among proposed activities for a specific WO budget level. Proposed WO activities will be evaluated against specific WO objectives that measure benefits of performing the work. The amount of funding recommended by the system for each activity depends on the degree to which the activity achieves WO objectives. DOE management would take the recommendation into consideration when making budgetary decisions.

The following objectives are being considered for the resource allocation support system to measure benefits and costs for different funding options: Maximize compliance with applicable environmental laws and agreements; minimize health and safety risks to workers and the public; minimize environmental impacts; minimize waste generation; and effectively treat, store, and dispose of waste generated by DOE programs, such as Defense Programs, Nuclear Energy, Energy Research, and Environmental Restoration.

DOE is interested in receiving comments on the proposed structure and on the objectives which should be used.

Paul D. Grimm,

Principal Deputy Assistant Secretary for Environmental Restoration and Waste Management.

[FR Doc. 91–28967 Filed 12–2–91; 8:45 am]

BILLING CODE 6450–01–M

Energy Information Administration

Agency Information Collections Under Review by the Office of Management and Budget

AGENCY: Energy Information Administration, DOE.

ACTION: Notice of request submitted for review by the Office of Management and Budget.

SUMMARY: The Energy Information Administration (EIA) has submitted the energy information collection(s) listed at the end of this notice to the Office of Management and Budget (OMB) for review under provisions of the Paperwork Reduction Act (Pub. L. No. 96-511, 44 U.S.C. 3501 *et seq.*). The listing does not include collections of information contained in new or revised regulations which are to be submitted under section 3504(h) of the Paperwork Reduction Act, nor management and procurement assistance requirements collected by the Department of Energy (DOE).

Each entry contains the following information: (1) The sponsor of the collection (a DOE component, which term includes the Federal Energy Regulatory Commission (FERC)); (2) Collection number(s); (3) Current OMB docket number (if applicable); (4) Collection title; (5) Type of request, e.g., new, revision, extension, or reinstatement; (6) Frequency of collection; (7) Response obligation, i.e., mandatory, voluntary, or required to obtain or retain benefit; (8) Affected public; (9) An estimate of the number of respondents per report period; (10) An estimate of the number of responses per respondent annually; (11) An estimate of the average hours per response; (12) The estimated total annual respondent burden; and (13) A brief abstract describing the proposed collection and the respondents.

DATES: Comments must be filed by January 2, 1992. If you anticipate that you will be submitting comments but find it difficult to do so within the time allowed by this notice, you should advise the OMB DOE Desk Officer listed below of your intention to do so as soon as possible. The Desk Officer may be telephoned at (202) 395-3084. (Also, please notify the EIA contact listed below.)

ADDRESSES: Address comments to the Department of Energy Desk Officer, Office of Information and Regulatory Affairs, Office of Management and Budget, 726 Jackson Place NW., Washington, DC 20503. (Comments should also be addressed to the Office of Statistical Standards at the address below.)

FOR FURTHER INFORMATION CONTACT: Jay Casselberry, Office of Statistical Standards, (EI-73), Forrestal Building, U.S. Department of Energy, Washington, DC 20585. Mr. Casselberry may be telephoned at (202) 254-5348.

SUPPLEMENTARY INFORMATION:

The energy information collection submitted to OMB for review was:

1. Federal Energy Regulatory Commission.
2. FERC-511.
3. 1902-0069.
4. Application for Transfer of Electric License.
5. Extension.
6. On occasion.
7. Mandatory.
8. Individuals or households, State or local governments, businesses or other for-profit, non-profit institutions, and small businesses or organizations.
9. 30 respondents.
10. 1 response.
11. 40 hours per response.
12. 1200 hours.
13. To carry out the requirement of part 1, sections 4(e) and 8 of the Federal Power Act. These sections direct that a hydroelectric license may be transferred upon application executed jointly by the parties of the proposed transfer and in agreement with the FERC.

Statutory Authority: Sec. 5(a), 5(b), 13(b), and 52, Pub. L. No. 93-275, Federal Energy Administration Act of 1974, 15 U.S.C. 764(a), 764(b), 772(b), and 790a.

Issued in Washington, DC, November 27, 1991.

Yvonne M. Bishop,

Director, Statistical Standards Energy Information Administration.

[FR Doc. 91-28972 Filed 12-2-91; 8:45 am]

BILLING CODE 6450-01-M

Federal Energy Regulatory Commission

[Docket Nos. ER92-194-000, et al.]

New England Power Co., et al.; Electric Rate, Small Power Production, and Interlocking Directorate Filings

Take notice that the following filings have been made with the Commission:

1. New England Power Co.

[Docket No. ER92-194-000]

November 22, 1991.

Take notice that on November 20, 1991, New England Power Company (NEP) filed three (3) Unit Power Contracts between NEP and (1) Central Vermont Public Service Corporation (CVPS); (2) Fitchburg Gas and Electric Light Company (Fitchburg); and (3) Chicopee Municipal Lighting Plant (Chicopee) for the sale of capacity from NEP's Brayton Point Unit 4 beginning November 1, 1991.

NEP requests waiver of the Commission's notice requirements so that the Contracts can be made effective and terminated in accordance with their terms.

Comment date: December 6, 1991, in accordance with Standard Paragraph E at the end of this notice.

2. Niagara Mohawk Power Corp.

[Docket No. ER92-195-000]

November 22, 1991.

Take notice that on November 20, 1991, Niagara Mohawk Power Corporation (Niagara Mohawk) tendered for filing a proposed change to Niagara Mohawk Rate Schedule No. 176, an agreement between Niagara Mohawk and the Rochester Gas & Electric Corporation.

Rate Schedule No. 176 provides for the wheeling of certain loads by Niagara Mohawk to RG&E. The proposed change revises the rates for the wheeling of power and energy by Niagara Mohawk. Niagara Mohawk proposes an effective date of September 1, 1991 and requests waiver of the Commission's notice requirements. In support thereof, Niagara Mohawk states that RG&E has consented to this proposed effective date.

Copies of this filing were served upon the Public Service Commission of the State of New York and Rochester Gas & Electric Corporation.

Comment date: December 6, 1991, in accordance with Standard Paragraph E at the end of this notice.

3. Kentucky Utilities Co.

[Docket No. ER92-149-000]

November 22, 1991.

Take notice that on November 1, 1991, Kentucky Utilities Company "Company") tendered for filing a Supplemental Agreement dated October 3, 1991 ("1991 Supplement") between Company and the City of Owensboro, Kentucky ("City") and the City Utilities Commission of the City of Owensboro, Kentucky ("Utility Commission"). The 1991 Supplement is to a contract between the parties, dated September 30, 1960, as supplemented. The 1991 Supplement provides for, among other matters, the City to issue new revenue bonds to provide funds for installation of pollution control equipment on the two generating units of the City's Station No. 2 and to establish a new Interest Revenue Account to cover the debt service, with funding based on allocation of capacity to each party. The 1991 Supplement also provides for a fund, based on allocation of capacity, for future decommissioning No. 2.

The Company states that payments into these funds will not affect current rates to customers and that a copy of the

filing was sent to the Public Service Commission of Kentucky, the City, and the Utility Commission.

Comment date: December 6, 1991, in accordance with Standard Paragraph E at the end of this notice.

4. Boston Edison Co.

[Docket No. ER92-150-000]

November 22, 1991.

Take notice that on November 1, 1991, Boston Edison Company (BECo) tendered for filing a Service Agreement and appendix A for The United Illuminating Company (UI) for the sale and/or exchange of power from time to time pursuant to BECo's Electric Tariff, Original Volume No. 6. BECo seeks waiver of the Commission's notice requirements so that these transactions may become effective on November 1, 1991.

Comment date: December 9, 1991, in accordance with Standard Paragraph E at the end of this notice.

5. Commonwealth Edison Co.

[Docket No. ER91-586-000]

November 25, 1991.

By letter dated August 12, 1991, Commonwealth Edison Company ("Edison") submitted for filing Amendment No. 2, dated July 15, 1991, to the Interconnection Agreement, dated July 1, 1979, as amended, between Edison, Northern Indiana Public Service company ("Northern Indiana"), and Commonwealth Edison Company of Indiana, Inc. ("Edison of Indiana"). Take notice that on November 15, 1991, Edison, in response to a request from Commission Staff, submitted additional cost and operational data to support its proposed rates. Also Edison, Northern Indiana, and Edison of Indiana have submitted a revised Amendment No. 2 which includes certain revenue constraint provisions for hourly and daily transactions conducted by Edison or Northern Indiana.

Edison has requested that the revised Amendment No. 2 be permitted to become effective as of August 12, 1991, and accordingly has requested that the Commission waive its notice requirements.

Comment date: December 9, 1991, in accordance with Standard Paragraph E at the end of this notice.

6. Tampa Electric Co.

[Docket No. ER92-192-000]

November 25, 1991.

Take notice that on November 19, 1991, Tampa Electric Company (Tampa Electric) tendered for filing Service Schedule G, providing for backup/reserve interchange service between Tampa Electric and Seminole Electric Cooperative, Inc. (Seminole). The service schedule is submitted as a supplement under the existing agreement for interchange service between Tampa Electric and Seminole.

Tampa Electric also tendered for filing, as a supplement to the Service Schedule G, a Letter of Commitment providing for the sale by Tampa Electric to Seminole of capacity and/or energy at an initial maximum hourly delivery rate of 50 megawatts.

Tampa Electric proposes an effective date of January 1, 1992 for the Service Schedule G and Letter of Commitment, and therefore requests waiver of the Commission's notice requirements.

Copies of the filing have been served on Seminole and the Florida Public Service Commission.

Comment date: December 9, 1991, in accordance with Standard Paragraph E at the end of this notice.

7. PacifiCorp Electric Operations

[Docket No. ER92-110-000]

November 25, 1991.

Take notice that PacifiCorp Electric Operations ("PacifiCorp"), on November 18, 1991, tendered for filing an amendment to its October 8, 1991 filing of the Draft Lost Creek Transmission Service Agreement (Draft Agreement) in this Docket.

The amended filing is being submitted to provide additional cost support for the rate to be charged for transmission service under the Draft Agreement.

PacifiCorp renews its requests for waiver of the Commission's regulations in order to allow an effective date of October 1, 1978 to be assigned to the Draft Agreement.

Copies of this amended filing were supplied to Bonneville Power Administration and the Public Utility Commission of Oregon.

Comment date: December 9, 1991, in accordance with Standard Paragraph E at the end of this notice.

8. Nevada Power Co.

[Docket No. ER92-190-000]

November 25, 1991.

Take notice that on November 18, 1991, Nevada Power Company (NPC), tendered for filing an agreement entitled Interconnection Agreement between Nevada Power Company and Citizens Utilities Company hereinafter the "Agreement". The primary purpose of the Agreement is to establish the terms and conditions for the interchange of economy, emergency, and banked energy and for other power transactions that may be possible through the Parties' interconnected systems through the systems of third Parties.

NPC states that copies of the filing were served upon Citizens Utilities Company.

Comment date: December 9, 1991, in accordance with Standard Paragraph E at the end of this notice.

9. Tucson Electric Power Co.

[Docket No. ER92-189-000]

November 25, 1991.

Take notice that Tucson Electric Power Company ("TEP") on November 18, 1991, tendered for filing a letter agreement supplementing the Power Services Agreement between TEP and the Arizona Electric Power Cooperative, Inc. ("AEPCO") and in particular, Service Schedule D to the Agreement. The letter agreement sets forth certain modifications regarding AEPCO's use of TEP's 345—kV transmission system between Vail and Greenlee Substations and TEP's use of AEPCO's system between Vail and Greenlee substations.

The Parties respectfully request that the Commission's regulations regarding filing be waived so the Agreement can become effective pursuant to its terms.

Copies of the filing were served upon all parties affected by this proceeding.

Comment date: December 9, 1991, in accordance with Standard Paragraph E at the end of this notice.

10. Central Vermont Public Service Corp.

[Docket No. ER92-188-000]

November 25, 1991.

Take notice that Central Vermont Public Service Corporation ("Central Vermont") on November 15, 1991, tendered for filing nineteen Service Agreements which provide for service pursuant to Central Vermont's Power Sales Tariff that was tendered for filing in Docket No. ER92-12-000.

Central Vermont requests that the Commission waive its notice requirement in order to allow the agreement to become effective on December 1, 1991 in accordance with its terms. In support of its request Central Vermont states that the Service Agreements were negotiated as quickly as possible after the Power Sales Tariff was filed and that some of the Service Agreements were signed forty-eight hours before being filed.

Comment date: December 9, 1991, in accordance with Standard Paragraph E at the end of this notice.

11. Niagara Mohawk Power Corp.

[Docket No. ER92-196-000]

November 25, 1991.

Take notice that on November 20, 1991, Niagara Mohawk Power Corporation ("Niagara Mohawk") tendered for filing a proposed change to Niagara Mohawk Rate Schedule No. 140, an agreement between Niagara Mohawk and the Orange & Rockland Utilities, Inc.

Rate Schedule No. 140 provides for the wheeling of certain loads by Niagara Mohawk to O&R. The proposed change revises the rates for the wheeling of power and energy by Niagara Mohawk. Niagara Mohawk proposes an effective date of September 1, 1991 and requests waiver of the Commission's notice requirements. In support thereof, Niagara Mohawk states that O&R has consented to this proposed effective date.

Copies of this filing were served upon the following:

Public Service Commission, State of New York, Three Empire State Plaza, Albany, NY 12223

and

Orange & Rockland Utilities, Inc., One Blue Hill Plaza, Pearl River, NY 10965.

Comment date: December 9, 1991, in accordance with Standard Paragraph E at the end of this notice.

Standard Paragraphs

E. Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, in accordance with rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). All such motions or protests should be filed on or before the comment date. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Lois D. Cashell,

Secretary.

[FR Doc. 91-28871 Filed 12-2-91; 8:45 am]

BILLING CODE 6717-01-M

[Project No. 10887 New York]

Climax Manufacturing Co.; Availability of Environmental Assessment

November 25, 1991.

In accordance with the National Environmental Policy Act of 1969 and the Federal Energy Regulatory Commission's (Commission's) regulations, 18 CFR part 380 (Order No. 486, 52 FR 47897), the Office of Hydropower Licensing has reviewed the application for minor license for the existing Carthage Paper Makers Mill Hydroelectric Project located on the Black River in Jefferson and Lewis Counties, near West Carthage, New York, and has prepared an Environmental Assessment (EA) for the project. In the EA, the Commission's staff has analyzed the environmental impacts of the project and has concluded that approval of the project, with appropriate mitigative measures, would not constitute a major federal action significantly affecting the quality for the human environment.

Copies of the EA are available for review in the Public Reference Branch, room 3308, of the Commission's offices at 941 North Capitol Street, NE., Washington, DC 20426.

Lois D. Cashell,

Secretary.

[FR Doc. 91-28872 Filed 12-2-91; 8:45 am]

BILLING CODE 6717-01-M

[Project No. 1333-001]

Pacific Gas and Electric Co., California; Availability of Environmental Assessment

November 25, 1991.

In accordance with the National Environmental Policy Act of 1969 and the Federal Energy Regulatory Commission's (Commission's) regulations, 18 CFR part 380 (Order No. 486, 52 FR 47897), the Office of Hydropower Licensing has reviewed the application for new license for the existing Tule River Project, located on the Tule River and its tributaries in Tulare County, California, near the town of Porterville, and has prepared an Environmental Assessment (EA) for the project. In the EA, the Commission's staff has analyzed the existing and potential future environmental impacts of the project and has concluded that approval of the project would not constitute a major federal action significantly affecting the quality of the human environment.

Copies of the EA are available for review in the Public Reference Branch, room 3104, of the Commission's offices at 941 North Capitol Street, NE., Washington, DC 20426.

Lois D. Cashell,

Secretary.

[FR Doc. 91-28873 Filed 12-2-91; 8:45 am]

BILLING CODE 6717-01-M

[Docket Nos. CP92-195-000, et al.]

El Paso Natural Gas Co., et al.; Natural Gas Certificate Filings

Take notice that the following filings have been made with the Commission:

1. El Paso Natural Gas Co.

[Docket No. CP92-195-000]

November 22, 1991.

Take notice that on November 18, 1991, El Paso Natural Gas Company (El Paso), P.O. Box 1492, Houston, Texas 79978, filed in Docket No. CP92-195-000 a request under §§ 157.205 and 157.212 of the Commission's Regulations under the Natural Gas Act (18 CFR 157.205 and 157.212) for authorization to construct and operate two new delivery taps to serve Southwest Gas Company (Southwest), under its blanket certificate issued in Docket No. CP82-435-000, all as more fully set forth in the request which is on file with the Commission and open to public inspection.

El Paso states that it has rendered sales service to Southwest under the terms and conditions of two service agreements dated October 15, 1970, as amended, and August 15, 1970, as amended. El Paso states that effective September 1, 1991, Southwest elected to convert its firm sales entitlements under its existing service agreements to firm transportation service under the provisions of its Global Settlement in Docket No. RP88-44-000, *et al.* El Paso also states that this firm transportation service is being rendered under two service agreements dated August 9, 1991. It is indicated that these agreements provide for the transportation of Southwest's full requirements to customers situated within the states of Arizona and Nevada. It is also indicated that as a part of the Global Settlement, El Paso's converting customers are permitted to request the additions of new delivery points, provided the facilities are economically justified.

El Paso states it received written requests from Southwest for the delivery of natural gas at two new points on El Paso's interstate system. It is indicated that Southwest has requested that El Paso provide these two new delivery points at a point on El Paso's existing 6-inch and 6⅝-inch O.D. Morenci Laterals

in Greenlee County, Arizona and at a point on El Paso's Mesa Irrigation Area Sales Lateral in Yuma County, Arizona. El Paso states that it has been advised that Southwest requires the delivery of these quantities of natural gas to serve the residential requirements of the Loma Linda and Verdee Lee communities and the small commercial requirements of the H & H Seed Company and the Peanut Patch.

El Paso states that to accommodate Southwest's requests, it proposes to construct and operate: (1) A one-inch tap and valve assembly, with appurtenances, at a point on the above-described Morenci Laterals and (2) a two-inch tap and valve assembly, with appurtenances, on the above-mentioned Mesa Irrigation Area Sales Lateral. El Paso estimates costs of the facilities at $10,932 and $8,815, respectively, to be financed with internally-generated funds. El Paso estimates that it would transport 15,606 Mcf and 4,988 Mcf, respectively, annually and 135 Mcf and 91 Mcf, respectively, on a peak day to the two new delivery points. El Paso also states that the deliveries to the new delivery points would have a negligible effects on its annual and peak day deliveries.

Comment date: January 6, 1992, in accordance with Standard Paragraph G at the end of this notice.

2. Tennessee Gas Pipeline Co.

[Docket Nos. CP89-629-009 and CP90-639-005

November 22, 1991.

Take notice that on November 8, 1991, Tennessee Gas Pipeline Company (Tennessee), 1010 Milan Street, Houston, Texas 77002, filed proposed changes in its Incremental Pressure Charge for Orchard Gas Corporation on behalf of MassPower, in compliance with the Commission's October 9, 1991 order.

Tennessee proposes to provide the higher delivery pressure for Orchard on behalf of MassPower and to charge an Incremental Pressure Charge to recover the costs associated with the higher delivery pressure. Tennessee indicates that it has revised the Incremental Pressure Charge consistent with the Commission's October 9 Order with one exception. With regard to the inclusion of certain fixed costs, notably depreciation expense, return, and taxes, Tennessee submits that these fixed costs are already included in the NET-DU tariff rate approved by the Commission. The details of the proposal are set forth more fully in the compliance filing which is on file with the Commission and open to public inspection

Tennessee submits that copies of the filing were served upon each person designated on the official service list.

Comment date: December 13, 1991, in accordance with the first subparagraph of Standard Paragraph F at the end of this notice.

3. Indeck Energy Service, Inc., et al.[1]

[Docket No. CI90-151-001]

November 22, 1991.

Take notice that on November 6, 1991, Indeck Energy Services, Inc., *et al.* (Indeck Energy) of 1130 Lake Cook Road, suite 300, Buffalo Grove, Illinois 60089, filed an application pursuant to sections 4 and 7 of the Natural Gas Act and the Federal Energy Regulatory Commission's (Commission) regulations thereunder to amend the unlimited-term blanket certificate with pregranted abandonment previously issued to Indeck Energy on September 28, 1990, by adding Indeck-Corinth Limited Partnership, Indeck-Ilion Limited Partnership, Indeck-Olean Limited Partnership, Indeck-Kirkwood Limited Partnership and Indeck-Yonkers Limited Partnership, all affiliates of Indeck Energy, all as more fully set forth in the application which is on file with the Commission and open for public inspection.

Comment date: December 12, 1991, in accordance with Standard Paragraph J at the end of this notice.

4. Northern Natural Gas Co.

[Docket No. CP92-178-000]

November 22, 1991.

Take notice that on November 12, 1991, Northern Natural Gas Company (Northern), P.O. Box 1188, Houston, Texas 77251-1188, filed in Docket No. CP92-178-000 an application, as supplemented on November 19, 1991 and November 20, 1991, under section 7(c) of the Natural Gas Act for issuance of a certificate authorizing the firm sales of natural gas to Westar Transmission Company, a subsidiary of American Pipeline Company (Westar), all as more fully set forth in the application which is on file with the Commission and open to public inspection.

Northern states that it would implement the firm sale to Westar of up to 50,000 million Btu of natural gas per day under the terms of a gas sales agreement dated September 13, 1991. It is indicated that Northern would provide authorized overrun service if in Northern's sole judgment it is capable of delivering the overrun volumes. Northern indicates that it would deliver the gas to Westar at any of six specified delivery points located in the state of Texas during the calendar months of December 1991 through February 1992. It is also indicated that Westar requires the gas to serve the winter peaking requirements of Energas, a local distribution company.

Northern states that Westar and Energas have entered into a sales agreement providing for Westar to furnish to Energas with sufficient gas supplies to meet its gas requirements through October 1998. It is indicated that although Westar's gas supply is sufficient to serve the requirements of Energas' customers, Westar is concerned that certain valid force majeure conditions such as well freeze ups and other producer-related problems could cause curtailments of Westar's gas supply from time to time. Northern also indicates that a majority of Energas's customers are high priority customers such as residences, hospitals, schools and other human needs customers. It is also stated that Westar was required to purchase emergency gas supplies from Northern under Northern's Rate Schedule E-1 during the 1988-89 heating season to avoid curtailment of Energas' high priority customers. Northern states that Westar does not desire to rely upon emergency service for heating seasons, and has requested instead a firm seasonal service.

For the firm service and authorized overrun service, Northern proposes to charge the Field Sales Rate as set forth on Sheet No. 1c of its FERC GAS Tariff, Original Volume No. 2. However, it is indicated that northern would charge an additional $0.46 per Mcf per day for volumes taken in excess of 9,000 Mcf per day. Northern states that no new facilities are required to implement the service.

Comment date: December 13, 1991, in accordance with Standard Paragraph F at the end of this notice.

5. Panhandle Eastern Pipe Line Co.

[Docket No. CP92-183-000]

November 22, 1991.

Take notice that on November 14, 1991, Panhandle Eastern Pipe Line Company (Panhandle), Post Office Box 1642, Houston, Texas 77001, filed in Docket No. CP92-183-000 an application pursuant to section 7(b) of the Natural

[1] The *et al.* parties are Indeck Energy Gas Supply Corporation, Indeck Energy Services of Corinth, Inc., Indeck Energy Services of Ilion, Inc., Indeck Energy Services of Kirkwood, Inc., Indeck Energy Services of Niagara, Inc., Indeck Energy Services of Olean, Inc., Indeck Energy Services of Silver Springs, Inc., Indeck Energy Services of Yonkers, Inc., Indeck-Oswego Limited Partnership, Indeck-Yerkes Limited Partnership, Indeck-Corinth Limited Partnership, Indeck-Ilion Limited Partnership, Indeck-Olean Limited Partnership, Indeck-Kirkwood Limited Partnership and Indeck-Yonkers Limited Partnership.

Gas Act, for permission and approval to abandon certain facilities located in Texas and Oklahoma, all as more fully set forth in the application which is on file with the Commission and open to public inspection.

Panhandle proposes to abandon and transfer its percent ownership to K N Energy, Inc. (K N) certain facilities jointly owned with K N, referred to as the Buffalo Wallow facilities. It is stated that the Buffalo Wallow facilities, which are located in Hemphill County, Texas and Roger Mills County, Oklahoma, include three compressor station sites with total compression of approximately 6,500 horsepower, approximately 68.6 miles of pipeline, and appurtenant facilities.

Panhandle states that the Buffalo Wallow facilities were initially constructed by Panhandle in 1969, as authorized by the Commission order in Docket Nos. CP69–266 and CP69–244, in coordination with the construction by K N of an adjacent gathering system. It is stated that the facilities were constructed pursuant to the March 11, 1969, agreement between Panhandle and K N, the joint owners of the facilities.

Panhandle indicates that it no longer relies on the gas produced from the Buffalo Wallow area to meet its customers' sales requirements and that the majority of its gas reserves in the Buffalo Wallow area have been released and the attendant gas purchase contracts have been terminated. Thus, it is explained that in conformance with a Contract Reformation/Take-or-Pay Settlement with K N, Panhandle has agreed to transfer its interest in the joint ownership of the facilities to K N. Panhandle states that it is its understanding that K N would use the facilities as part of its pipeline system and that all facilities proposed to be abandoned by Panhandle would remain in place. It is further indicated that K N would provide transportation for Panhandle's remaining contracted gas supply under its open-access transportation tariff.

Comment date: December 13, 1991, in accordance with Standard Paragraph F at the end of the notice.

6. Panhandle Eastern Pipe Line Co.

[Docket No. CP92–190–000]

November 22, 1991.

Take notice that on November 18, 1991, Panhandle Eastern Pipe Line Company (Panhandle), Post Office Box 1642, Houston, Texas 77251–1642, filed in Docket No. CP92–190–000 an application pursuant to section 7(b) of the Natural Gas Act, for permission and approval to abandon certain facilities located in Colorado, all as more fully set forth in the application which is on file with the Commission and open to public inspection.

Panhandle proposes to abandon and sell to K N Energy, Inc. (K N) certain facilities located in Adams, Arapahoe, Boulder, Larimer and Weld Counties, Colorado, which Panhandle refers to as its Wattenberg System. It is stated that the facilities proposed to be abandoned include: (1) Eleven compressor station sites with approximately 45,000 horsepower; (2) approximately 1,275 miles of various sized pipeline; and (3) small field buildings and appurtenant facilities.

Panhandle states that it originally received authorization to construct and operate the Wattenberg System in an order issued in Docket No. CP72–181, as amended (49 FPC 823 (1973)). It is indicated that due to the vast changes in the interstate gas transmission industry, Panhandle no longer relies on the gas produced from the reserve connected to the Wattenberg System to meet its customers' sales requirements. Panhandle adds that most of the gas that was originally dedicated to Panhandle on the Wattenberg System has been released from contract and that to the extent that Panhandle continues to purchase gas on the Wattenberg System, K N would provide transportation service to Panhandle.

It is stated that K N will be filing an application pursuant to section 7(c) of the Natural Gas Act to own and operate the transmission portion of the Wattenberg System and a petition for issuance of a declaratory order pursuant to the provisions of part 385 of the Commission's Regulations requesting that the Commission determine portions of the Wattenberg System nonjurisdictional gathering facilities.

Panhandle indicates that the proposed abandonment would not adversely affect local producers since K N would provide open access transportation subject to the Commission's jurisdiction.

Comment date: December 13, 1991, in accordance with Standard Paragraph F at the end of this notice.

7. Northern Natural Gas Co., Division of Enron Corp.

[Docket No. CP92–192–000]

November 22, 1991.

Take notice that on November 18, 1991, Northern Natural Gas Company, Division of Enron Corp. (Northern), 1111 South 103rd Street, Omaha, Nebraska 68124–1000, filed a prior notice request with the Commission in Docket No. CP92–192–000 pursuant to § 157.205 of the Commission's Regulations under the Natural Gas Act (NGA) for authorization to operate as a jurisdictional facility an existing delivery point for deliveries to Peoples Natural Gas Company, a Division of Utilicorp, Inc. (Peoples) for use by the community of Hanston, located in Hodgeman County, Kansas, under the blanket certificate issued in Docket No. CP82–401–000, pursuant to section 7 of the NGA, all as more fully set forth in the request which is open to public inspection.

Northern states that the facilities were installed under the authorization of section 311 of the Natural Gas Policy Act and that Northern now wishes to operate the delivery point as a jurisdictional facility pursuant to the provisions of part 284, subpart B of the Commission's Regulations. It is stated that the deliveries would be for residential and commercial end use. It is asserted that the volumes to be delivered to Peoples at the proposed delivery point would be within Peoples' currently authorized firm entitlement from Northern and that the volumes delivered to Peoples for Hanston would come from the firm entitlement assigned to the community of Jetmore. Northern states that the proposed deliveries would not impact its peak day or annual deliveries.

Comment date: January 6, 1992, in accordance with Standard Paragraph G at the end of this notice.

8. United Gas Pipe Line Co.

[Docket No. CP92–194–000]

November 22, 1991.

Take notice that on November 18, 1991, United Gas Pipe Line Company (United), P.O. Box 1478, Houston, Texas 77251–1478, filed in Docket No. CP92–194–000 an application pursuant to section 7(b) of the Natural Gas Act for permission and approval to partially abandon sales service to four customers effective January 1, 1991, all as more fully set forth in the request which is on file with the Commission and open to public inspection.

United requests authorization to reduce the contract sales Maximum Daily Quantity (MDQ) to Canton Municipal Utilities (Canton), Mississippi Valley Gas (MVG), the City of Pascagoula, Mississippi (Pascagoula) and the City of Pensacola, Florida (Pensacola) as shown in the following chart:

Firm sales customer	Existing MDQ level (Mcf/d)	Proposed MDQ level (Mcf/d)
Canton	8,990	6,990
MVG	123,412	80,000
Pascagoula	14,545	6,999
Pensacola	63,013	45,000

United's settlement in RP91.126 *et al.*, authorized the establishment of new service levels for all of United's jurisdictional customers. No facilities are proposed to be abandoned herein.

Comment date: December 13, 1991, in accordance with Standard Paragraph F at the end of the notice.

9. Algonquin Gas Transmission Co.

[Docket No. CP92-180-000]

November 25, 1991.

Take notice that on November 13, 1991, Algonquin Gas Transmission Company (Algonquin), 1284 Soldiers Field Road Boston, MA 02135, filed in Docket No. CP92-180-000, pursuant to section 7 of the Natural Gas Act, for a certificate of public convenience and necessity authorizing (1) the construction and operation of certain facilities; (2) the transportation on a firm basis of up to 20,000 MMBtu for Boston Edison Company (Boston Edison), and (3) the abandonment of certain facilities, all as more fully set forth in the application, which is on file with the Commission and is open to public inspection.

Algonquin proposes to provide firm transportation service for Boston Edison under proposed new Rate Schedule X-40 for service from the new receipt point in Mendon, Massachusetts to a delivery point on the mainline at the head of the Edgar Lateral near Avon, Massachusetts. Algonquin proposes to charge an incremental rate consisting of a one-part demand charge for this service. Additionally, quantities in excess of the Maximum Daily Transportation Quantity would be subject to overrun charges. The proposed rate is designed to ensure recovery of the total cost of constructing the necessary facilities. In order to provide the service for Boston Edison, Algonquin proposes to abandon and replace 3.9 miles of 26-inch pipeline with 36-inch pipeline from Main Line Valve 14 to Algonquin's Stony Point Compressor Station in Stony Point, New York.

Algonquin estimates that the total cost of its proposed construction activities to be $9.3 million. Applicant states that it intends to finance its project costs through ongoing regular financing programs and internally generated funds.

Comment date: December 16, 1991, in accordance with Standard Paragraph F at the end of this notice.

10. Superior Offshore Pipeline Co.

[Docket No. CP92-189-000]

November 25, 1991.

Take notice that on November 18, 1991, Superior Offshore Pipeline Company (SOPCO), 12450 Greenspoint Drive, Houston, Texas 77060-1991, filed in Docket No. CP92-189-000 an application pursuant to section 7(c) of the Natural Gas Act for authorization to continue the operation of facilities which were previously constructed pursuant to section 311 of the Natural Gas Policy Act (NGPA), under the blanket certificate authorization granted to SOPCO in Docket No. CP86-387-000, all as more fully set forth in the application which is on file with the Commission and open to public inspection.

SOPCO states that in 1989 and 1990 it constructed two 12.75-inch O.D. pipeline laterals consisting of approximately 2.0 miles and 4.8 miles from the tailgate outlet of Trident NGL, Inc.'s Lowry Processing plant located in Cameron Parish, Louisiana to points of interconnection with the interstate pipeline facilities of Texas Gas Transmission Corporation (Texas Gas) and Columbia Gulf Transmission Corporation (Columbia Gulf) located respectively in Cameron and Jefferson Davis Parishes, Louisiana. SOPCO states further that the facilities were constructed pursuant to NGPA section 311 and transportation service has been provided under NGPA section 311 (a)(1) also.

It is said that the Columbia Gulf pipeline lateral was constructed at a cost of approximately 1.464 million dollars and the Texas Gas pipeline lateral was constructed at a cost of approximately 2.048 million dollars.

SOPCO proposes to operate these pipeline facilities pursuant to section 7(c) of the Natural Gas Act so that any shipper, without regard to NGPA section 311, may when available, receive service.

Comment date: December 16, 1991, in accordance with Standard Paragraph F at the end of this notice.

11. Unigas Corporation

[Docket No. CI92-10-000]

November 25, 1991

Take notice that on November 15, 1991, Unigas Corporation (Unigas) of 150-6th Avenue, SW., suite 3520, Calgary, Alberta, Canada T2P 3Y7 filed an application pursuant to sections 4 and 7 of the Natural Gas Act and the Federal Energy Regulatory Commission's (Commission) regulations thereunder for an unlimited-term blanket certificate with pregranted abandonment authorizing sales for resale in interstate commerce of natural authorizing sales for resale in interstate commerce of natural gas subject to the Commission's NGA jurisdiction including imported natural gas, all as more fully set forth in the application which is on file with the Commission and open for public inspection.

Comment date: December 13 1991, in accordance with Standard Paragraph J at the end of this notice.

Standard Paragraphs

F. Any person desiring to be heard or make any protest with reference to said filing should on or before the comment date file with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, a motion to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214) and the Regulations under the Natural Gas Act (18 CFR 157.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a motion to intervene in accordance with the Commission's Rules.

Take further notice that pursuant to the authority contained in and subject to jurisdiction conferred upon the Federal Energy Regulatory Commission by sections 7 and 15 of the Natural Gas Act and the Commission's Rules of Practice and Procedure, a hearing will be held without further notice before the Commission or its designee on this filing if no motion to intervene is filed within the time required herein, if the Commission on its own review of the matter finds that a grant of the certificate is required by the public convenience and necessity. If a motion for leave to intervene is timely filed or if the Commission on its own motion believes that a formal hearing is required, further notice of such hearing will be duly given.

Under the procedure herein provided for, unless otherwise advised, it will be unnecessary for the applicant to appear or be represented at the hearing.

G. Any person or the Commission's staff may, within 45 days after the issuance of the instant notice by the Commission file pursuant to rule 214 of

the Commission's Procedural Rules (18 CFR 385.214) a motion to intervene or notice of intervention and pursuant to § 157.205 of the Regulations under the Natural Gas Act (18 CFR 157.205) a protest to the request. If no protest is filed within the time allowed therefore, the proposed activity shall be deemed to be authorized effective the day after the time allowed for filing a protest. If a protest is filed and not withdrawn within 30 days after the time allowed for filing a protest, the instant request shall be treated as an application for authorization pursuant to section 7 of the Natural Gas Act.

Standard Paragraph

J. Any person desiring to be heard or make any protest with reference to said filings should on or before the comment date file with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426 a motion to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 385.211, .214). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party in any proceeding herein must file a petition to intervene in accordance with the Commission's rules.

Under the procedure herein provided for, unless otherwise advised, it will be unnecessary for the applicant to appear on be represented at the hearing.

Lois D. Cashell,

Secretary

[FR Doc. 91-28877 Filed 12-2-91; 8:45 am]

BILLING CODE 6717-01-M

[Docket Nos. TA92-2-82-001 and RP92-29-000]

Viking Gas Transmission Co.; Tariff Filing

November 25, 1991.

Take notice that on November 21, 1991, Viking Gas Transmission Company (Viking) filed Second Substitute Sixteenth Revised Sheet No. 6 and Third Revised Sheet No. 170 to Original Volume No. 1 of its FERC Gas Tariff to be effective November 1, 1991.

Viking states that the tariff sheets were filed in compliance with the Commission's November 7, 1991 order in Docket Nos. TA92-2-82-000, *et al.*

Viking states that the purpose of the revisions on Second Substitute Sixteenth Revised Sheet No. 6 is to reflect the Commission's denial of Viking's request for a waiver of § 154.306(b)(3) of the Commission's Regulations; the annualization of the fixed costs shifted from the demand component to the commodity component pursuant to the Commission's denial of Viking's request for a waiver; a decrease in the demand rates as a result of the subsequent renegotiation of the gas purchase contract and transportation agreement between Viking and Western Gas Marketing, U.S.A., Ltd. (WGM) and TransCanada PipeLines, Ltd. (TransCanada) to reduce the contract demand level for the 1991-1992 contract year effective as of November 1, 1991; and lower projected annual volumes due to customer conversions from sales to transportation service and the increase in the commodity rate due to the Commission's denial of the requested waiver.

Viking states that the Current Purchased Gas Cost Rate Adjustments reflected on Second Substitute Sixteenth Revised Sheet No. 6 consist of a $(.3356) per dekatherm adjustment to the gas rate, a $(.5630) per dekatherm adjustment to the Rate Schedule SR-1 commodity rate, and a $(6.85) per dekatherm adjustment to the demand rates.

Viking states that the revisions also reflect a $.3562 per dekatherm surcharge adjustment to the gas rates and a $1.48 per dekatherm adjustment to the demand rates for amortizing the Unrecovered Gas Cost Account.

Viking states that copies of the filing have been mailed to all of its customers and affected state regulatory commissions.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, in accordance with rules 211 and 214 of the Commission's Rules of Practice and Procedure. All such motions or protests should be filed on or before December 2, 1991. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene.

Lois D. Cashell,

Secretary.

[FR Doc. 91-28878 Filed 12-2-91; 8:45 am]

BILLING CODE 6717-01-M

[Docket No. RP90-111-014]

East Tennessee Natural Gas Co.; Place Settlement Rates Into Effect

November 25, 1991.

Take notice that on November 21, 1991, East Tennessee Natural Gas Company (East Tennessee), filed a motion to place into effect on December 1, 1991, the interim settlement rates approved in this proceeding. The rates are set forth on First Revised Twelfth Revised Sheet Nos. 4 and 5 to Volume No. 1 of East Tennessee's FERC Gas Tariff and Second Revised Sheet Nos. 6 and 7 to Volume No. 1A of East Tennessee's FERC Gas Tariff.

East Tennessee states that it also submits for filing the following revised tariff sheets to Volume Nos. 1 and 1A of its FERC Gas Tariff to be effective December 1, 1991:

Volume No. 1

Original Sheet No. 87A.
Original Sheet No. 91A.
Original Sheet No. 111A.
First Revised Sheet Nos. 20-23, 30-35, 40-44, 50, 60-62, 80, 82-87, 88-90, 93-95, 97, 98, 100-105, 111, 117, 130-137, 140-144 and 150-152.
Second Revised Sheet No. 91
Third Revised Sheet Nos. 115 and 116

Volume No. 1A

First Revised Sheet Nos. 24, 26, 45 and 107

East Tennessee certifies that it has served its filing upon each person on the service list of this proceeding.

Any person desiring to protest said filing should file a protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, in accordance with Rule 211 of the Commission's Rules of Practice and Procedure 18 CFR 385.211. All such protests should be filed on or before December 3, 1991. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Copies of this filing are on file with the Commission and are available for public inspection.

Lois D. Cashell,

Secretary.

[FR Doc. 91-28876 Filed 12-2-91; 8:45 am]

BILLING CODE 6717-01-M

[Docket No. RP92-31-000]

Paiute Pipeline Co.; Proposed Change in FERC Gas Tariff

November 25, 1991.

Take notice that on November 21, 1991, Paiute Pipeline Company (Paiute)

tendered for filing First Revised Sheet No. 56 of its FERC Gas Tariff, First Revised Volume No. 1-A, for the purpose of making changes to its operating procedure to place the timing of its scheduling of gas receipts and deliveries for firm transportation service on an equivalent basis with the scheduling revisions made by Paiute's upstream pipeline supplier, Northwest Pipeline Corporation (Northwest), in Docket No. RP92-12-000.

Paiute states that it has requested the Commission to grant a waiver of any applicable rules and regulations necessary so as to permit the tendered tariff sheet to become effective upon 30 days' notice.

Paiute states that copies of the filing were served upon Paiute's jurisdictional customers, interested parties and state regulatory commissions.

Any person desiring to be heard or to protest said filing should file a motion to intervene or a protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, in accordance with rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). All such motions or protests should be filed on or before December 2, 1991. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party to a proceeding must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

Lois D. Cashell,

Secretary.

[FR Doc. 91-28875 Filed 12-2-91; 8:45 am]

BILLING CODE 6717-01-M

[Docket No. RP89-179-012]

Western Gas Interstate Co.; Compliance Filing

November 25, 1991.

Take notice that on November 21, 1991, Western Gas Interstate Company (Western) tendered for filing certain tariff sheets to Second Revised Volume No. 1 of its FERC Gas Tariff, listed on Attachments A and B attached to the filing.

Western states that the tariff sheets in Attachment A are filed in order to correct Western's compliance tariff filings dated February 13 and 15, 1991, in the above-referenced docket.

Western states that the tariff sheet listed in Attachment B are revised reserved sheets reflecting language changes suggested by the staff.

The proposed effective date for the tariff sheets listed on Attachment A is March 1, 1991, and the proposed effective date for tariff sheets listed on Attachment B is January 1, 1992.

Western states that copies of the tariff sheets were mailed to its customers and interested state regulatory commissions.

Any person desiring to protest said filing should file a protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, in accordance with rule 211 of the Commission's Rules of Practice and Procedure 18 CFR 385.211. All such protests should be filed on or before December 3, 1991. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Copies of this filing are on file with the Commission and are available for public inspection.

Lois D. Cashell,

Secretary.

[FR Doc. 91-28874 Filed 12-2-91; 8:45 am]

BILLING CODE 6717-01-M

Office of Energy Research

Health and Environmental Research Advisory Committee; Renewal

Pursuant to section 14(a)(2)(A) of the Federal Advisory Committee Act, and § 101-6.1015 of the Final Rule on Advisory Committee Management, (41 CFR 101-6.1015) and following consultation with the Committee Management Secretariat, General Services Administration, notice is hereby given that the Health and Environmental Research Advisory Committee has been renewed for a two-year period. The Committee will provide advice to the Director, Office of Energy Research, on the Health and Environmental Research (HER) program.

The Committee presently has 18 members. The membership is balanced to include representatives of the national laboratories, the universities and the business sector. Important disciplines such as experimental biological research, ecological research, and medicine are well represented; and experience, point of view and geography are taken into account in the selection of the Committee members.

The renewal of the Health and Environmental Research Advisory Committee has been determined to be essential to the conduct of the Department's business and to be in the public interest in connection with the performance of duties imposed upon the Department of Energy by law. The Committee will operate in accordance with the provisions of the Federal Advisory Committee Act (Pub. L. No. 92-463), the Department of Energy Organization Act (Pub. L. No. 95-91), and regulations and directives implementing those statutes. Further information regarding this advisory committee can be obtained from Frederica Cravens (202-586-3282).

Issued in Washington, DC on November 22, 1991.

Howard H. Raiken,

Advisory Committee Management Officer.

[FR Doc. 91-28973 Filed 12-2-91; 8:45 am]

BILLING CODE 6450-01-M

Office of Fossil Energy

[FE Docket No. 91-90-NG]

Marathon Oil Co.; Application To Export Natural Gas to Mexico

AGENCY: Office of Fossil Energy, DOE.

ACTION: Notice of application for blanket authorization to export natural gas to Mexico.

SUMMARY: The Office of Fossil Energy of the Department of Energy (DOE) gives notice of receipt on October 29, 1991, of an application filed by Marathon Oil Company (Marathon) requesting blanket authorization to export up to 73 Bcf of natural gas to Mexico over a two-year period commencing with the date of first delivery. Marathon intends to use existing U.S. pipeline facilities which interconnect with Mexican pipeline facilities at various points on the U.S./Mexican border. Marathon states that it will submit quarterly reports detailing each transaction.

The application was filed under section 3 of the natural Gas Act and DOE Delegation Order Nos. 0204-111 and 0204-127. Protests, motions to intervene, notices of intervention and written comments are invited.

DATES: Protests, motions to intervene, or notices of intervention, as applicable, requests for additional procedures and written comments are to be filed at the address listed below no later than 4:30 p.m., eastern time, January 2, 1992.

ADDRESSES: Office of Fuels Programs, Fossil Energy, U.S. Department of Energy, Forrestal Building, room 3F-056, FE-50, 1000 Independence Avenue, SW., Washington, DC 20585.

FOR FURTHER INFORMATION:

Charles E. Blackburn, Office of Fuels Programs, Fossil Energy, U.S. Department of Energy, Forrestal

Building, room 3F-094, 1000 Independence Avenue, SW., Washington, DC 20585, (202) 586-7751

Lot Cooke, Office of Assistant General Counsel for Fossil Energy, U.S. Department of Energy, Forrestal Building, room 6E-042, 1000 Independence Avenue, SW., Washington, DC 20585, (202) 586-0503.

SUPPLEMENTARY INFORMATION: Marathon is a Ohio corporation with its principal place of business in Houston, Texas. Marathon intends to export the natural gas for its own account as well as for the accounts of U.S. suppliers and Mexican purchasers.

Marathon states that it will sell the requested natural gas volumes on a short-term or spot basis and the contractual arrangements will be the product of arms-length negotiations with an emphasis on competitive prices and contract flexibility.

The export application will be reviewed under section 3 of the Natural Gas Act and the authority contained in DOE Delegation Order Nos. 0204-111 and 0204-127. In deciding whether the proposed export is in the public interest, domestic need for the natural gas will be considered, and any other issue determined to be appropriate, including whether the arrangement is consistent with DOE policy of promoting competition in the natural gas marketplace by allowing commercial parties to freely negotiate their own trade arrangements. Parties, especially those that may oppose this application, should comment on these matters as they relate to the requested export authority. The applicant asserts that there is no current need for the domestic gas that would be exported under the proposed arrangement. Parties opposing this arrangement bear the burden of overcoming this assertion.

NEPA Compliance

The National Environmental Policy Act (NEPA), 42 U.S.C. 4321 *et seq.*, requires DOE to give appropriate consideration to the environmental effects of its proposed actions. No final decision will be issued in this proceeding until DOE has met its NEPA responsibilities.

Public Comment Procedure

In response to this notice, any person may file a protest, motion to intervene or notice of intervention, as applicable, and written comments. Any person wishing to become a party to the proceeding and to have their written comments considered as the basis for any decision on the application must, however, file a motion to intervene or notice of intervention, as applicable. The filing of a protest with respect to this application will not serve to make the protestant a party to the proceeding, although protests and comments received from persons who are not parties will be considered in determining the appropriate action to be taken on the application. All protests, motions to intervene, notices of intervention, and written comments must meet the requirements that are specified by the regulations in 10 CFR part 590. Protests, motions to intervene, notices of intervention, requests for additional procedures, and written comments should be filed with the Office of Fuels Programs at the address listed above. It is intended that a decisional record on the application will be developed through responses to this notice by parties, including the parties' written comments and replies thereto. Additional procedures will be used as necessary to achieve a complete understanding of the facts and issues. A party seeking intervention may request that additional procedures be provided, such as additional written comments, an oral presentation, a conference, or trial-type hearing. Any request to file additional written comments should explain why they are necessary. Any request for an oral presentation should identify the substantial necessary question of fact, law, or policy at issue, show that it is material and relevant to a decision in the proceeding, and demonstrate why an oral presentation is needed. Any request for a conference should demonstrate why the conference would materially advance the proceeding. Any request for a trial-type hearing must show that there are factual issues genuinely in dispute that are relevant and material to a decision and that a trial-type hearing is necessary for a full and true disclosure of the facts.

If an additional procedure is scheduled, notice will be provided to all parties. If no party requests additional procedures, a final opinion and order may be issued based on the official record, including the application and responses filed by parties pursuant to this notice, in accordance with 10 CFR 590.316.

A copy of Marathon's application is available for inspection and copying in the Office of Fuels Programs Docket Room, room 3F-056 at the above address. The docket room is open between the hours of 8 a.m. and 4:30 p.m., Monday through Friday, except Federal holidays.

Issued in Washington, DC on November 22, 1991.

Clifford P. Tomaszewski,

Acting Deputy Asssistant Secretary for Fuels Programs, Office of Fossil Energy.

[FR Doc. 91-28968 Filed 12-2-91; 8:45 am]

BILLING CODE 6450-01-M

Cases Filed With the Office of Hearings and Appeals; During the Week of August 30 Through September 6, 1991

During the Week of August 30 through September 6, 1991, the appeals and the applications for other relief listed in the appendix to this Notice were filed with the Office of Hearings and Appeals of the Department of Energy.

Under DOE procedural regulations, 10 CFR part 205, any person who will be aggrieved by the DOE action sought in these cases may file written comments on the application within ten days of service of notice, as prescribed in the procedural regulations. For purposes of the regulations, the date of service of notice is deemed to be the date of publication of this Notice or the date of receipt by an aggrieved person of actual notice, whichever occurs first. All such comments shall be filed with the Office of Hearings and Appeals, Department of Energy, Washington, DC 20585.

Dated: November 26, 1991.

George B. Breznay,

Director, Office of Hearings and Appeals.

LIST OF CASES RECEIVED BY THE OFFICE OF HEARINGS AND APPEALS

[Week of August 30 through September 6, 1991]

Date	Name and location of applicant	Case No.	Type of Submission
Sept. 4, 1991	Gulf/Larry's Gulf, Monroe, Michigan	RR300-109	Request for Modification/Rescission in the Gulf Refund Proceeding. IF GRANTED: The April 17, 1991 Decision and Order (Case No. RF300-11400) issued to Larry's Gulf would be modified regarding the firm's application for refund submitted in the Gulf Refund Proceeding.

LIST OF CASES RECEIVED BY THE OFFICE OF HEARINGS AND APPEALS—Continued

[Week of August 30 through September 6, 1991]

Date	Name and location of applicant	Case No.	Type of Submission
Sept. 5, 1991	James L. Schwab, Monroe, Michigan	LFA-0144	Appeal of an Information Request Denial. If granted: The August 14, 1991, Freedom of Information Request Denial issued by the Office of Inter-governmental and External Affairs, Albuquerque Operations Office, (AOO) would be rescinded and James L. Schwab would receive certain information concerning the AOO's investigation into the termination of his employment with a DOE subcontractor
Sept. 6, 1991	Paul G. Richards, Palisades, New York	LFA-0146	Appeal of an Information Request Denial. If Granted: The July 31, 1991, Freedom of Information Request Denial issued by the Office of Classification, Security Affairs, would be rescinded, and Paul G. Richards would receive access to the event yield of five specific underground nuclear explosions conducted at the Nevada Test Site.

REFUND APPLICATIONS RECEIVED

[Week of August 30 through September 6, 1991]

Date received	Name of refund proceeding/name of refund applicant	Case No.
9/4/91	West Pike Shell	RF315-10159
9/4/91	Exeter Shell Service.	RF315-10160
9/4/91	Hercules, Inc.	RF336-24
9/5/91	Paul's Biscayne Shell.	RF315-10161
9/3/91	George A. Bourbon.	RF335-41
9/3/91	Downtown Shell & Tire Service.	RF315-10157
9/3/91	Jerry's Super Shell Service.	RF315-10158
9/3/91	Bill's ARCO	RF304-12496
9/3/91	Bill's ARCO	RF304-12497
9/3/91	Oakwood ARCO	RF304-12498
9/4/91	State Escrow Distribution.	RF302-11
8/30/91 thru 9/6/91	Texaco Refund Applications Received.	RF321-16780 thru FR 321-16812
8/30/91 thru 9/6/91	Crude Oil Refund Applications Received.	RF272-89672 thru FR 272-89764
8/30/91 thru 9/6/91	Gulf Oil Refund Applications Received.	RF300-17550 thru FR 300-17580

[FR Doc. 91-28974 Filed 12-2-91; 8:45 am]

BILLING CODE 6450-01-M

ENVIRONMENTAL PROTECTION AGENCY

[FRL-4037-8]

Science Advisory Board Drinking Water Committee; Open Meeting; December 17-19, 1991

Pursuant to the Federal Advisory Committee Act, Public Law 92-463, notice is hereby given that the Science Advisory Board's (SAB) Drinking Water Committee (DWC) will meet on December 17-19, 1991 at the U.S. EPA, Environmental Research Center, Route 54 and Alexander Drive, Research Triangle Park, NC 27711. The meeting will begin at 9 a.m. on December 17th. It is anticipated that the DWC will complete its deliberations no later than 12 p.m. on December 19th, although it may finish sooner. The meeting is open to the public and seating is on a first-come basis.

PURPOSE AND CHARGE TO THE COMMITTEE: The purpose of the meeting is for the Committee to review the Agency's health research program for drinking water, providing advice on whether the program is appropriately targeted, scientifically and programmatically, given the level of resources provided (this draft charge to the Committee is subject to revision).

FOR FURTHER INFORMATION: For details concerning this meeting, including a draft agenda, please contact Mr. Robert Flaak, Assistant Staff Director, Science Advisory Board (A-101F), U.S. Environmental Protection Agency, 401 M Street, SW., Washington, DC 20460. Telephone: (202) 260-652 and FAX: (202) 260-7118. There are no review documents or other materials being provided to the DWC prior to the meeting. Members of the public who wish to make a brief oral presentation to the Committee must contact Mr. Flaak no later than Wednesday, December 11, 1991 in order to be included on the Agenda. Written statements of any length (at least 15 copies) may be provided to the Committee up until the meeting. The Science Advisory Board expects that public statements presented at its meetings will not be repetitive of previously submitted oral or written statements. In general, each individual or group making an oral presentation will be limited to a total time of five minutes.

Dated: November 22, 1991.

Dr. Donald Barnes,

Staff Director, Science Advisory Board.

[FR Doc. 91-28961 Filed 12-2-91, 8:45 am]

BILLING CODE 6560-50-M

[OPTS-59302A; FRL 4005-9]

Certain Chemicals; Approval of a Test Marketing Exemption

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: This notice announces EPA's conditional approval of an application for test marketing exemption (TME) under section 5(h)(1) of the Toxic Substances Control Act (TSCA) and 40 CFR 720.38. EPA has designated this application as TME-92-1. The test marketing conditions are described below.

EFFECTIVE DATE: November 25, 1991.

FOR FURTHER INFORMATION CONTACT: David Di Fiore, New Chemicals Branch, Chemical Control Division (TS-794), Office of Toxic Substances, Environmental Protection Agency, rm. E-611E, 401 M St., SW., Washington, DC 20460, (202) 260-3374.

SUPPLEMENTARY INFORMATION: Section 5(h)(1) of TSCA authorizes EPA to exempt persons from premanufacture notification (PMN) requirements and permit them to manufacture or import new chemical substances for test marketing purposes if the Agency finds that the manufacture, processing, distribution in commerce, use, and disposal of the substances for test marketing purposes will not present an unreasonable risk of injury to health or the environment. EPA may impose restrictions on test marketing activities and may modify or revoke a test marketing exemption upon receipt of new information which casts significant doubt on its finding that the test marketing activity will not present an unreasonable risk of injury.

EPA hereby approves TME-92-1. EPA has determined that test marketing of the new chemical substance described below, under the conditions set out in the TME application and amendment, and for the time period and restrictions

specified below, will not present an unreasonable risk of injury to health or the environment. Production volume, use, and the number of customers must not exceed that specified in the application. All other conditions and restrictions described in the application, amendment, and in this notice must be met.

The following additional restrictions apply to TME-92-1.

1. The applicant must ensure that each person who is reasonably likely to be dermally exposed in the work area to the TME substance through direct handling or through contact with equipment on which the substance may exist is required to wear personal protective equipment that provides a barrier to prevent dermal exposure to the substance in the specific work area where it is selected for use. Required protective equipment for this TME substance should include, at a minimum, impervious gloves and safety goggles or a face shield. Each item of protective equipment must be selected and used in accordance with 29 CFR 1910.132 and 1910.133.

2. The applicant must ensure that employees are provided with information and training on the TME substance. This information and training must be provided at the time of each employee's initial assignment to a work area containing the TME substance and whenever the substance is introduced into the employee's work area for the first time.

3. The applicant must affix a label to each container of the substance or formulations containing the substance. The label shall include, at a minimum, the following statement:

WARNING: Contact with skin may be harmful. Chemicals similar in structure to (insert appropriate name) have been found to cause oncogenicity and retinopathy. To protect yourself, you must wear protective gloves, clothing, and goggles.

4. The applicant is prohibited from any predictable or purposeful release of the TME substance or of any waste stream from the processing or use of the substance into the waters of the United States.

5. The applicant may only distribute the TME substance, other than for disposal, to a customer who agrees in writing to comply with the same requirements and restrictions to which the applicant must adhere: personal protective equipment, hazard communication, and environmental release.

6. A bill of lading accompanying each shipment must state that the use of the substance is restricted to that approved in the TME. In addition, the applicant shall maintain the following records until 5 years after the date they are created, and shall make them available for inspection or copying in accordance with section 11 of TSCA:

a. Records of the quantity of the TME substance produced and the date of manufacture.

b. Records of dates of the shipments to each customer and the quantities supplied in each shipment.

c. Copies of the bill of lading that accompanies each shipment of the TME substance.

d. Copies of the labels affixed to containers of the substance or formulations containing the substance.

e. Records documenting the determinations required by paragraph 1 of this TME that chemical protective clothing is impervious to the TME substance.

f. Records documenting establishment and implementation of the hazard communication program required by paragraph 2 of this TME.

g. A copy of the letter supplied by each customer that agrees to comply with the same requirements and restrictions that pertain to the applicant.

h. Records documenting appropriate disposal of the TME substance and the quantities so disposed of.

TME-92-1

Date of Receipt: October 17, 1991.

Notice of Receipt: October 28, 1991 (56 FR 55500).

Applicant: Lonza Inc.

Chemical: (S) Benzenamine, 4,4'-methylenebis[2-methyl-6-(1-methylethyl)]-.

Use: (G) Open non-dispersive use.

Production Volume: Confidential.

Number of Customers: Two.

Test Marketing Period: 730 days, commencing on first day of commercial manufacture.

Risk Assessment: EPA identified the following health concerns for the test market substance: cancer, based on analogy to methylene dianiline; and retinopathy, based on the TME chemical's structure. However, these concerns are mitigated by the requirement that workers who are exposed to the TME substance wear gloves, goggles and other protective equipment, and by the prohibition on releases of the TME substance to water.

EPA also identified environmental concerns for the TME chemical. Based on a quantitative structure activity relationship to anilines, EPA expects chronic toxicity to aquatic organisms to occur at a concentration of 1 part per billion TME substance in surface waters. The applicant has agreed, however, not to release any of the TME chemical to water, thereby mitigating the Agency's concerns for aquatic toxicity.

The EPA concludes, therefore, that, based on the mitigation factors described above, the test market activities will not present an unreasonable risk of injury to health or the environment.

The Agency reserves the right to rescind approval or modify the conditions and restrictions of an exemption should any new information cast significant doubt on its finding that the test marketing activities will not present an unreasonable risk of injury to health or the environment.

Dated: November 25, 1991.

John W. Melone,

Director, Chemical Control Division, Office of Toxic Substances.

[FR Doc. 91-28962 Filed 12-2-91; 8:45 am]

BILLING CODE 6560-50-F

FEDERAL COMMUNICATIONS COMMISSION

Public Information Collection Requirements Submitted to Office of Management and Budget for Review

November 22, 1991.

The Federal Communications Commission has submitted the following information collection requirements to OMB for review and clearance under the Paperwork Reduction Act of 1980 (44 U.S.C. 3507).

Copies of these submissions may be purchased from the Commission's copy contractor, Downtown Copy Center, 1114 21st Street, NW., Washington, DC 20036, (202) 452-1422. For further information on these submissions contact Judy Boley, Federal Communications Commission, (202) 632-7513. Persons wishing to comment on these information collections should contact Jonas Neihardt, Office of Management and Budget, Room 3235 NEOB, Washington, DC 20503, (202) 395-4814.

OMB Number: 3060-0190.

Title: Section 73.3544, Application to obtain a modified station license.

Action: Extension.

Respondents: Non-profit institutions, businesses or other for-profit (including small businesses).

Frequency of Response: On occasion reporting.

Estimated Annual Burden: 249 responses; 1 hour average burden per response; 249 hours total annual burden.

Needs and Uses: Section 73.3544 sets forth the filing procedures for broadcast

licensees to obtain a modified station license when prior authority is not required to make the changes. Licensees are required to notify the FCC in writing when there is a change in the name of the licensee where there is no change in ownership or control. TV or FM licensees changing the type of transmitting antenna or output power of their transmitter must file the appropriate construction permit application form with the FCC. The data is used by FCC staff to ensure changes are in accordance with FCC rules and regulations and to issue a modified station license.

OMB Number: 3060–0187.

Title: Section 73.3594, Local public notice of designation for hearing.

Action: Extension.

Respondents: Businesses or other for-profit (including small businesses).

Frequency of Response: On occasion reporting.

Estimated Annual Burden: 693 responses; 4 hours average burden per response; 2,772 hours total annual burden.

Needs and Uses: Section 73.3594 requires that applicants of any AM, FM or TV broadcast station designated for hearing must give notice of such designation. Section 73.3594(a) requires that this notice be given in a daily newspaper of general circulation published in the community in which the station is or will be located. Section 73.3594(b) requires applicants for modification, assignment, transfer or renewal of an operating broadcast station to give notice over the broadcast station in addition to publishing the notice in a daily newspaper. Section 73.3595(g) requires that applicants file a statement with the FCC setting forth information regarding the publication or broadcast.

OMB Number: 3060–0314.

Title: Section 76.209, Fairness doctrine; personal attacks, political editorials.

Action: Extension.

Respondents: Businesses or other for-profit (including small businesses).

Frequency of Response: On occasion reporting.

Estimated Annual Burden: 1,312 responses; 2.6 hours average burden per response; 3,411 hours total annual burden.

Needs and Uses: During the presentation of views on a controversial issue of public importance, an attack may be made upon the honesty, character, integrity, or like personal qualities of an identified person or group. Section 76.209(b) requires that a cable television system operator must transmit to the person or group attacked a notification of the date, time and identification of the cablecast of a personal attack; a script or tape of the attack, and an offer of a reasonable opportunity to respond to the attack over the licensee's facilities. Section 76.209(d) requires that when a cable television system operator in an editorial endorses or opposes a candidate, the licensee must notify the other qualified candidate(s) for the same office or the candidate opposed, of the date and time of editorial, provide a script or tape of the editorial and offer reasonable opportunity to respond over the system's facilities. The data is used as a notification of personal attack and to provide an opportunity to respond to a political editorial.

OMB Number: 3060–0308.

Title: Section 90.505, Developmental operation, showing required.

Action: Extension.

Respondents: State or local governments, non-profit institutions, and businesses or other for-profit (including small businesses).

Frequency of Response: On occasion reporting.

*Estimated Annual Burden:*100 responses; 2 hours average burden per response; 200 hours total annual burden.

Needs and Uses: Developmental authorizations are usually employed by licensees who wish to develop some new use of the radio communication facilities. By their very nature, these developmental uses vary considerably and do not lend themselves to defined usage categories already in the Rules. Accordingly, applicants proposing such operations are required to submit supplemental information showing why the authorization is necessary and what its use will be. The data is used by FCC staff to evaluate the desirability of issuing such an authorization from spectrum use and interference potential considerations.

Federal Communications Commission.

William F. Caton,

Acting Secretary.

[FR Doc. 91–28892 Filed 12–2–91; 8:45 am]

BILLING CODE 6712-01-M

FEDERAL MARITIME COMMISSION

Brazil/U.S. Gulf Ports; Agreement(s) Filed

The Federal Maritime Commission hereby gives notice of the filing of the following agreement(s) pursuant to section 5 of the Shipping Act of 1984.

Interested parties may inspect and obtain a copy of each agreement at the Washington, DC Office of the Federal Maritime Commission, 1100 L Street, NW., room 10325. Interested parties may submit comments on each agreement to the Secretary, Federal Maritime Commission, Washington, DC 20573, within 10 days after the date of the **Federal Register** in which this notice appears. The requirements for comments are found in § 572.603 of title 46 of the code of Federal Regulations. Interested persons should consult this section before communicating with the Commission regarding a pending agreement.

Agreement No.: 212–010320–025.

Title: Brazil/U.S. Gulf Ports Agreement

Parties: Compania de Navegacao Lloyd Brasileiro Companhia Maritima Nacional American Transport Lines, Inc. Empresa Lineas Maritimas Argentinas S.A. A. Bottacchi S.A. de Navegacion C.F.I.I. ("Bottacchi")

Synopsis: The modification would delete Bottacchi as a party to the Agreement, extend alternate coast service through 1992, provide for two six-month pool periods in 1992, provide that only five percent of the revenue earned by the parties will be subject to pooling during the first pool period in 1992, extend the current undercarriage forfeiture clause through 1992, and permit any party to withdraw at the end of the first pool period of 1992 upon 30 days' notice. The parties have requested a shortened review period.

Agreement No.: 232–011359.

Title: Sea-Land/Navieras Space Charter Agreement.

Parties: Puerto Rico Maritime Shipping Authority Sea-Land Service, Inc.

Synopsis: Under the terms of the proposed Agreement, one of the parties will withdraw from service the vessel it operates between Puerto Rico and Trinidad, and serve that trade route via space chartered abroad the vessel operated by the other party, as well as make calls at the Dominican Republic. The parties will also mutually establish a schedule for service to the Agreement trade with the operating vessel. The Agreement serves the trade between ports and points in Puerto Rico, and other U.S. ports and points served via Puerto Rico, and ports and points in the Dominican Republic and the Republic of Trinidad and Tobago.

By Order of the Federal Maritime Commission.

Dated: November 26, 1991.

Joseph C. Polking,

Secretary.

[FR Doc. 91-28852 Filed 1-22-91; 8:45 am]

Billing Code 6730-01-M

Security for the Protection of the Public; Financial Responsibility to Meet Liability Incurred for Death or Injury to Passengers or Other Persons on Voyages; Issuance of Certificate (Casualty)

Notice is hereby given that the following have been issued a Certificate of Financial Responsibility to Meet Liability Incurred for Death or Injury to Passengers or Other Persons on Voyages pursuant to the provisions of section 2, Public Law 89-777 (46 U.S.C. 817(d)) and the Federal Maritime Commission's implementing regulations at 46 CFR part 540, as amended:

Compagnie Francaise de Croisieres and Sodimarit S.A., c/o Ocean Cruise Lines, Inc., 1510 SE. 17th Street, Ft. Lauderdale, FL 33316.

Vessel: OCEAN PRINCESS.

Dated: November 26, 1991.

Joseph C. Polking,

Secretary.

[FR Doc. 91-28888 Filed 12-2-91; 8:45 am]

BILLING CODE 6730-01-M

Ocean Freight Forwarder License; Applicants

Notice is hereby given that the following applicants have filed with the Federal Maritime Commission applications for licenses as ocean freight forwarders pursuant to section 19 of the Shipping Act of 1984 (46 U.S.C. app. 1718 and 46 CFR part 510).

Persons knowing of any reason why any of the following applicants should not receive a license are requested to contact the Office of Freight Forwarders, Federal Maritime Commission, Washington, DC 20573

DFM International Inc., 130 Produce Ave. H, San Francisco, CA 94121
Officers: Frank J. Havlat, President, Jon C. Brownfield, Vice President/Director, Dale Wilson, Secretary/Director

Ventana Overseas Cargo Inc., 30-01 37th Avenue, Long Island City, New York 11101
Officers: Eleuterio Arcese, Chairman, Paola Arcese, Director, Pier Antonio Baragiola, Director, George Ringhoff, Vice President/General Manager

Amerpole International, Inc., 220 McClellan Highway, E. Boston, MA 02128
Officers: Alfred Landano, Director, Michael Landano, Director, Anna Landano, Treasurer

Alicia Seneca Walker, 10801 SW 30th Street, Miami, FL 33165, Sole Proprietor

Global Freight Inc., 426 Northfield Ave., Edison, NJ 08837
Officers: Savino Illuzzi, President/Director, Frank Vasta, Vice President/Secretary/Director

America's Custom Brokers, Inc., 1900 N.W. 82nd Ave., Miami, FL 33126
Officer: Jorge J. Sam, President/Director

NRS America Inc., 405 Lexington Ave., 48 Fl., New York, NY 10174
Officers: Masayoshi Uchara, Chairman, Hiroshi Aoki, Director, Hiroshi Takubo, Director, Tomio Banzai, President/Treasurer, David Hiromura, Vice President/Secretary, Yoichi Noto, Vice President, I-Huang Lin, Vice President, Susan Onuma, Assistant Secretary

Vintage Express Inc., 2750 N. 29th Ave., Suite 202, Hollywood, FL 33020
Officer: Roberta C.L. Robbert, President/Director

Youngs Transport Inc., 1330 Broadway, #1012, Oakland, CA 94612
Officers: Doug H. Lee, President/Director, John S. Lee, Treasurer

AIS International, Inc., One Mass Tech Center, P.O. 522, E. Boston, MA 02128
Officers: Joanne M. McDevitt, President, James D. MacDonald, Director

Interfreight Customs Clearance Inc., 999 E. Touhy Ave., #480, Des Plaines, IL 60018
Officers: Kurt Knondi-Floch, Chief Exec. Officer/Director, Herbert Hassinger, President/Stockholder, Roseann Zaffino, Vice President/Stockholder, Terry S. Kase, Secretary/Treasurer/Stockholder, Kurt A. Konodi, Director, Stefanie Williams, Director

Fisher Transport Inc., 1675 S. Elmhurst Rd., Elk Grove Village, IL 60007
Officers: Tom Jong-Ha Kim, President, Suzie Kim, Vice President

Dated: November 26, 1991.

By the Federal Maritime Commission.

Joseph C. Polking,

Secretary.

[FR Doc. 91-28851 Filed 12-2-91; 8:45 am]

BILLING CODE 6730-01-M

FEDERAL RESERVE SYSTEM

Earl Ford McNaughton; Change in Bank Control Notice, Acquisition of Shares of Banks or Bank Holding Companies

The notificant listed below has applied under the Change in Bank Control Act (12 U.S.C. 1817(j)) and § 225.41 of the Board's Regulation Y (12 CFR 225.41) to acquire a bank or bank holding company. The factors that are considered in acting on notices are set forth in paragraph 7 of the Act (12 U.S.C. 1817(j)(7)).

The notice is available for immediate inspection at the Federal Reserve Bank indicated. Once the notice has been accepted for processing, it will also be available for inspection at the offices of the Board of Governors. Interested persons may express their views in writing to the Reserve Bank indicated for the notice or to the offices of the Board of Governors. Comments must be received not later than December 24, 1991.

A. Federal Reserve Bank of Chicago (David S. Epstein, Vice President) 230 South LaSalle Street, Chicago, Illinois 60690:

1. Earl Ford McNaughton, Fremont, Indiana; to acquire 78.32 percent of the voting shares of San Jose Banco, Inc., Fremont, Indiana, and thereby indirectly acquire San Jose Tri-County Bank, San Jose, Illinois.

Board of Governors of the Federal Reserve System, November 26, 1991.

Jennifer J. Johnson,

Associate Secretary of the Board.

[FR Doc. 91-28889 Filed 12-2-91; 8:45 am]

BILLING CODE 6210-01-F

Provident Bancorp, Inc., et al.; Formations of; Acquisitions by; and Mergers of Bank Holding Companies

The companies listed in this notice have applied for the Board's approval under section 3 of the Bank Holding Company Act (12 U.S.C. 1842) and § 225.14 of the Board's Regulation Y (12 CFR 225.14) to become a bank holding company or to acquire a bank or bank holding company. The factors that are considered in acting on the applications are set forth in section 3(c) of the Act (12 U.S.C. 1842(c)).

Each application is available for immediate inspection at the Federal Reserve Bank indicated. Once the application has been accepted for processing, it will also be available for inspection at the offices of the Board of Governors. Interested persons may

express their views in writing to the Reserve Bank or to the offices of the Board of Governors. Any comment on an application that requests a hearing must include a statement of why a written presentation would not suffice in lieu of a hearing, identifying specifically any questions of fact that are in dispute and summarizing the evidence that would be presented at a hearing.

Unless otherwise noted, comments regarding each of these applications must be received not later than December 24, 1991.

A. Federal Reserve Bank of Cleveland (John J. Wixted, Jr., Vice President) 1455 East Sixth Street, Cleveland, Ohio 44101:

1. Provident Bancorp, Inc., Cincinnati, Ohio; to acquire 100 percent of the voting shares of Provident Bank of Boone County, Burlington, Kentucky, and Provident Bank of Kenton County, Covington, Kentucky.

B. Federal Reserve Bank of Chicago (David S. Epstein, Vice President) 230 South LaSalle Street, Chicago, Illinois 60690:

1. Pyramid Bancorp, Inc., Grafton, Wisconsin; to become a bank holding company by acquiring up to 100 percent of the voting shares of Grafton State Bank, Grafton, Wisconsin.

2. San Jose Banco, Inc., Fremont, Indiana; to acquire 80 percent of the voting shares of The First National Bank of Fremont, Fremont, Indiana.

C. Federal Reserve Bank of San Francisco (Kenneth R. Binning, Director, Bank Holding Company) 101 Market Street, San Francisco, California 94105:

1. Investors Banking Corporation, Portland, Oregon; to become a bank holding company by acquiring 66 2/3 percent of the voting shares of Colonial Banking Company, Grants Pass, Oregon, a *de novo* bank.

Board of Governors of the Federal Reserve System, November 26, 1991.

Jennifer J. Johnson,

Associate Secretary of the Board.

[FR Doc. 91-28890 Filed 12-2-91; 8:45 am]

BILLING CODE 6210-01-F

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Alcohol, Drug Abuse, and Mental Health Administration

Current List of Laboratories Which Meet Minimum Standards to Engage in Urine Drug Testing for Federal Agencies

AGENCY: National Institute on Drug Abuse, ADAMHA, HHS.

ACTION: Notice.

SUMMARY: The Department of Health and Human Services notifies Federal agencies of the laboratories currently certified to meet standards of subpart C of Mandatory Guidelines for Federal Workplace Drug Testing Programs (53 FR 11979, 11986). A similar notice listing all currently certified laboratories will be published during the first week of each month, and updated to include laboratories which subsequently apply for and complete the certification process. If any listed laboratory's certification is totally suspended or revoked, the laboratory will be omitted from updated lists until such time as it is restored to full certification under the Guidelines.

FOR FURTHER INFORMATION CONTACT: Denise L. Goss, Program Assistant, Drug Testing Section, Division of Applied Research, National Institute on Drug Abuse, room 9-A-53, 5600 Fishers Lane, Rockville, Maryland 20857; tel.: (301) 443-6014.

SUPPLEMENTARY INFORMATION: Mandatory Guidelines for Federal Workplace Drug Testing were developed in accordance with Executive Order 12564 and section 503 of Public Law 100-71. Subpart C of the Guidelines, "Certification of Laboratories Engaged in Urine Drug Testing for Federal Agencies," sets strict standards which laboratories must meet in order to conduct urine drug testing for Federal agencies. To become certified an applicant laboratory must undergo three rounds of performance testing plus an on-site inspection. To maintain that certification a laboratory must participate in an every-other-month performance testing program plus periodic, on-site inspections.

Laboratories which claim to be in the applicant stage of NIDA certification are not to be considered as meeting the minimum requirements expressed in the NIDA Guidelines. A laboratory must have its letter of certification from HHS/NIDA which attests that it has met minimum standards.

In accordance with subpart C of the Guidelines, the following laboratories meet the minimum standards set forth in the Guidelines:

AccuTox Analytical Laboratory, 427 Fifth Avenue, NW., Attalla, AL 35954-0770, 205-538-0012

Aegis Analytical Laboratories, Inc., 624 Grassmere Park Road, suite 21, Nashville, TN 37211, 615-331-5300,

Alabama Reference Laboratories, Inc., 543 South Hull Street, Montgomery, AL 36103, 205-263-5745

American Medical Laboratories, Inc., 11091 Main Street, P.O. Box 188, Fairfax, VA 22030, 703-691-9100

Associated Pathologists Laboratories, Inc., 4230 South Burnham Avenue, suite 250, Las Vegas, NV 89119-5412, 702-733-7866

Associated Regional and University Pathologists, Inc. (ARUP), 500 Chipeta Way, Salt Lake City, UT 84108, 801-583-2787

Bayshore Clinical Laboratory, 4555 W. Schroeder Drive, Brown Deer, WI 53223, 414-355-4444/800-877-7016

Bellin Hospital-Toxicology Laboratory, 2789 Allied Street, Green Bay, WI 54304, 414-496-2487

Bioran Medical Laboratory, 415 Massachusetts Avenue, Cambridge, MA 02139, 617-547-8900

Cedars Medical Center, Department of Pathology, 1400 Northwest 12th Avenue, Miami, FL 33136, 305-325-5810

Center for Human Toxicology, 417 Wakara Way-Room 290, University Research Park, Salt Lake City, UT 84108, 801-581-5117

Columbia Biomedical Laboratory, Inc., 4700 Forest Drive, suite 200, Columbia, SC 29206, 800-848-4245/803-782-2700

Clinical Pathology Facility, Inc., 711 Bingham Street, Pittsburgh, PA 15203, 412-488-7500

Clinical Reference Lab, 11850 West 85th Street, Lenexa, KS 66214, 800-445-6917

CompuChem Laboratories, Inc., 3308 Chapel Hill/Nelson Hwy., P.O. Box 12652, Research Triangle Park, NC 27709, 919-549-826/800-833-3984

Cox Medical Centers, Department of Toxicology, 1423 North Jefferson Avenue, Springfield, MO 65802, 800-876-3652/417-836-3093

Damon Clinical Laboratories, 140 East Ryan Road, Oak Creek, WI 53154, 800-365-3840 (name changed: formerly Chem-Bio Corporation; CBC Clinilab)

Damon Clinical Laboratories, 8300 Esters Blvd., suite 900, Irving, TX 75063, 214-929-0535

Doctors & Physicians Laboratory, 801 East Dixie Avenue, Leesburg, FL 32748, 904-787-9006

Drug Labs of Texas, 15201 I 10 East, suite 125, Channelview, TX 77530, 713-457-3784

DrugScan, Inc., P.O. Box 2969, 1119 Mearns Road, Warminster, PA 18974, 215-674-9310

Eagle Forensic Laboratory, Inc., 950 North Federal Highway, suite 308, Pompano Beach, FL 33062, 305-946-4324

Eastern Laboratories, Ltd., 95 Seaview Boulevard, Port Washington, NY 11050, 516-625-9800

ElSohly Laboratories, Inc., 1215-½ Jackson Ave., Oxford, MS 38655, 601-236-2609

Employee Health Assurance Group, 405 Alderson Street, Schofield, WI 54476, 800-627-8200 (name change: formerely Alpha Medical Laboratory, Inc.)

General Medical Laboratories, 36 South Brooks Street, Madison, WI 53715, 608-267-6267

Laboratory of Pathology of Seattle, Inc., 1229 Madison St., suite 500, Nordstrom Medical Tower, Seattle, WA 98104, 206-386-2672

Laboratory Specialists, Inc., 113 Jarrell Drive, Belle Chasse, LA 70037, 504-392-7961

Mayo Medical Laboratories, 200 S.W. First Street, Rochester, MN 55905, 800-533-1710/507-284-3631

Med-Chek Laboratories, Inc., 4900 Perry Highway, Pittsburgh, PA 15229, 412-931-7200
MedExpress/National Laboratory Center, 4022 Willow Lake Boulevard, Memphis, TN 38175, 901-795-1515
MedTox Bio-Analytical, a Division of MedTox Laboratories, Inc., 9176 Independence Avenue, Chatsworth, CA 91311, 818-718-0115/800-331-8670 (outside CA)/800-464-7081 (CA only) (name changed: formerly Laboratory Specialists, Inc., Abused Drug Laboratories)
MedTox Bio-Analytical, a Division of MedTox Laboratories, Inc., 2356 North Lincoln Avenue, Chicago, IL 60614, 312-880-6900 (name changed: formerly Bio-Analytical Technologies)
MedTox Laboratories, Inc., 402 W. County Road D, St Paul, MN 55112, 612-636-7466/800-832-3244
Mental Health Complex Laboratories, 9455 Watertown Plank Road, Milwaukee, WI 53226, 414-257-7439
Methodist Medical Center Toxicology Laboratory, 221 N.E. Glen Oak Avenue, Peoria, IL 61636, 800-752-1835/309-671-5199
MetPath, Inc., 1355 Mittel Boulevard, Wood Dale, IL 60191, 708-595-3888
MetPath, Inc., One Malcolm Avenue, Teterboro, NJ 07608, 201-393-5000
MetWest-BPL Toxicology Laboratory, 18700 Oxnard Street, Tarzana, CA 91356, 800-492-0800/818-343-8191
National Center for Forensic Science, 1901 Sulphur Spring Road, Baltimore, MD 21227, 301-247-9100, (name changed: formerly Maryland Medical Laboratory, Inc.)
National Drug Assessment Corporation, 5419 South Western, Oklahoma City, OK 73109, 800-749-3784 (name changed: formerly Med Arts Lab)
National Health Laboratories Incorporated, 13900 Park Center Road, Herndon, VA 22071, 703-742-3100/800-572-3734 (inside VA)/800-336-0391(outside VA)
National Health Laboratories Incorporated, d.b.a. National Reference Laboratory, Substance Abuse Division, 1400 Donelson Pike, Suite A-15, Nashville, TN 37217, 615-360-3992/800-800-4522
National Health Laboratories Incorporated, 2540 Empire Drive, Winston-Salem, NC 27103-6710, 919-760-4620/800-334-8627 (outside NC)/800-642-0894 (NC only)
National Psychopharmacology Laboratory, Inc., 9320 Park W. Boulevard, Knoxville, TN 37923, 800-251-9492
National Toxicology Laboratories, Inc., 1100 California Avenue, Bakersfield, CA 93304, 805-322-4250
Nichols Institute Substance Abuse Testing (NISAT), 8985 Balboa Avenue, San Diego, CA 92123, 800-446-4728/619-694-5050 (name changed: formerly Nichols Institute)
Northwest Toxicology, Inc., 1141 E. 3900 South, Salt Lake City, UT 84124, 800-322-3361
Oregon Medical Laboratories, P.O. Box 972, 722 East 11th Avenue, Eugene, OR 97440-0972, 503-687-2134
Parke DeWatt Laboratories, Division of Comprehensive Medical Systems, Inc., 1810 Frontage Rd., Northbrook, IL 60062, 708-480-4680
Pathlab, Inc., 16 Concord, El Paso, TX 79906, 800-999-7284
Pathology Associates Medical Laboratories, East 11604 Indiana, Spokane, WA 99206, 509-926-2400
PDLA, Inc., 100 Corporate Court, So. Plainfield, NJ 07080, 908-769-8500/800-237-7352
PharmChem Laboratories, Inc., 1505-A O'Brien Drive, Menlo Park, CA 94025, 415-328-6200/800-446-5177
Poisonlab, Inc., 7272 Clairemont Mesa Road, San Diego, CA 92111, 619-279-2600
Precision Analytical Laboratories, Inc., 13300 Blanco Road, Suite #150, San Antonio, TX 78216, 512-493-3211
Puckett Laboratory, 4200 Mamie Street, Hattiesburgh, MS 39402, 601-264-3856/800-844-8378
Regional Toxicology Services, 15305 N.E. 40th Street, Redmond, WA 98052, 206-882-3400
Roche Biomedical Laboratories, 1801 First Avenue South, Birmingham, AL 35233, 205-581-3537
Roche Biomedical Laboratories, 1957 Lakeside Parkway, suite 542, Tucker, GA 30084, 404-939-4811
Roche Biomedical Laboratories, Inc., 1912 Alexander Drive, P.O. Box 13973, Research Triangle Park, NC 27709, 919-361-7770
Roche Biomedical Laboratories, Inc., 69 First Avenue, Raritan, NJ 08869, 800-437-4986
Roche Biomedical Laboratories, Inc., 1120 Stateline Road, Southaven, MS 38671, 601-342-1286
S.E.D. Medical Laboratories, 500 Walter NE, suite 500, Albuquerque, NM 87102, 505-848-8800
Sierra Nevada Laboratories, Inc., 888 Willow Street, Reno, NV 89502, 800-648-5472
SmithKline Beecham Clinical Laboratories, 7600 Tyrone Avenue, Van Nuys, CA 91045, 818-376-2520
SmithKline Beecham Clinical Laboratories, 3175 Presidential Drive, Atlanta, GA 30340, 404-934-9205 (name changed: formerly SmithKline Bio-Science Laboratories)
SmithKline Beecham Clinical Laboratories, 506 E. State Parkway, Schaumburg, IL 60173, 708-885-2010 (name changed: formerly International Toxicology Laboratories)
SmithKline Beecham Clinical Laboratories, 11636 Administration Drive, St. Louis, MO 63146, 314-567-3905
SmithKline Beecham Clinical Laboratories, 400 Egypt Road, Norristown, PA 19403, 800-523-5447 (name changed: formerly SmithKline Bio-Science Laboratories)
SmithKline Beecham Clinical Laboratories, 8000 Sovereign Row, Dallas, TX 75247, 214-638-1301 (name changed: formerly SmithKline Bio-Science Laboratories)
South Bend Medical Foundation, Inc., 530 North Lafayette Boulevard, South Bend, IN 46601, 219-234-4176
Southgate Medical Laboratory, Inc., 21100 Southgate Park Boulevard, 2nd Floor, Maple Heights, OH 44137, 800-338-0166 outside OH/800-362-8913 inside OH
St. Anthony Hospital (Toxicology Laboratory), P.O. Box 205, 1000 North Lee Street, Oklahoma City, OK 73102, 405-272-7052
St. Louis University Forensic Toxicology Laboratory, 1205 Carr Lane, St. Louis, MO 63104, 314-577-8628
Toxicology & Drug Monitoring Laboratory, University of Missouri Hospital & Clinics, 301 Business Loop 70 West, suite 208, Columbia, MO 65203, 314-882-1273
Toxicology Testing Service, Inc., 5426 N.W. 79th Avenue, Miami, FL 33166, 305-593-2260

Charles R. Schuster,

Director, National Institute on Drug Abuse.

[FR Doc. 91-29001 Filed 12-2-91; 8:45 am]

BILLING CODE 4160-20-M

Centers for Disease Control

National Institute for Occupational Safety and Health; Meeting

The National Institute for Occupational Safety and Health (NIOSH) of the Centers for Disease Control (CDC) announces the following meeting.

Name: Methods of Assessing Information Processing Demands.

Time and Date: 9 a.m.-4 p.m., December 10, 1991.

Place: Robert A. Taft Laboratories, Room SB-32, NIOSH, CDC, 4676 Columbia Parkway, Cincinnati, Ohio 45226.

Status: Open to the public, limited only by the space available.

Purpose: To conduct an open meeting for the review of a research protocol to study the effects of information processing demands in the production of musculoskeletal discomfort in keyboard work.

Contact Person for Additional Information: Naomi G. Swanson, NIOSH, CDC, 4676 Columbia Parkway, Mailstop C-24, Cincinnati, Ohio 45226, telephone 513/533-8293 or FTS 684-8293.

Dated: November 26, 1991.

Elvin Hilyer,

Associate Director for Policy Coordination, Centers for Disease Control.

[FR Doc. 91-28905 Filed 12-2-91; 8:45 am]

BILLING CODE 4160-19-M

Food and Drug Administration

[Docket No. 91n-0474]

Chelsea Laboratories, Inc.; Withdrawal of Approval of 10 Abbreviated New Drug Applications

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is withdrawing approval of 10 abbreviated new drug applications (ANDA's) held by Chelsea Laboratories, Inc., 896 Orlando Ave., West Hempstead, NY 11552 (Chelsea). Chelsea has agreed to voluntarily recall these drugs from the market, has agreed in writing to permit FDA to withdraw

approval of the applications, and has waived its opportunity for a hearing. This action stems from the discovery of discrepancies, false statements, and omissions concerning information used to support approval of the applications.

EFFECTIVE DATE: December 3, 1991.

FOR FURTHER INFORMATION CONTACT: Richard S. Lev, Center for Drug Evaluation and Research (HFD-366), Food and Drug Administration, 5600 Fishers Lane, Rockville, MD 20857, 301-295-8041.

SUPPLEMENTARY INFORMATION: Recently, FDA became award of untrue statements, discrepancies, and omissions that relate to batches of drug products used to support approval of the following ANDA's held by Chelsea:

ANDA 70-038, Ibuprofen Tablets, 400 milligrams (mg);
ANDA 70-041, Ibuprofen Tablets, 600 mg;
ANDA 70-952, Doxepin HC1 Capsules, 10 mg;
ANDA 70-953, Doxepin HC1 Capsules, 25 mg;
ANDA 70-954, Doxepin HC1 Capsules, 50 mg;
ANDA 70-955, Doxepin HC1 Capsules, 100 mg;
ANDA 71-763, Doxepin HC1 Capsules, 75 mg;
ANDA 70-764, Doxepin HC1 Capsules, 150 mg;
ANDA 70-911, Ibuprofen Tablets, 800 mg; and
ANDA 86-796, Chlorothiazide Tablets, 500 mg.

FDA has determined that these untrue statements, discrepancies, and omissions raise substantial questions about the reliability of the data, including the bioequivalence data, submitted in support of the applications. FDA informed Chelsea of this determination. Subsequently, Chelsea agreed to permit FDA to withdraw approval of the applications, thereby waiving its opportunity for a hearing.

Chelsea has not contested the factual findings of untrue statements, discrepancies, and omissions, but rather has argued that, despite the inaccuracies in the applications, the marketed products are bioequivalent to the respective listed drugs.

Therefore, under section 505(e) of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 355(e)), and under authority delegated to the Director of the Center for Drug Evaluation and Research (21 CFR 5.82), approval of the ANDA's listed above, and all amendments and supplements thereto, is withdrawn effective December 3, 1991. Distribution of these products in interstate commerce without an approved application is illegal and subject to regulatory action.

Dated: November 22, 1991.

Carl C. Peck,

Director, Center for Drug Evaluation and Research.

[FR Doc. 91-28984 Filed 12-2-91; 8:45 am]

BILLING CODE 4160-01-M

National Institutes of Health

National Institute on Aging; "Proteases and Protease Inhibitors—Emerging Roles in the Pathogenesis of Alzheimer's Disease"

Notice is hereby given of the National Institute on Aging (NIA) sponsored conference, "Proteases and Protease Inhibitors—Emerging Roles in the Pathogenesis of Alzheimer's Disease" to be held December 16-18, 1991 on the campus of the National Institutes of Health (NIH), Building 31C, Conference Room 10 (6th Floor), 9000 Rockville Pike, Bethesda, Maryland.

The purpose of this meeting is to bring together researchers in Alzheimer's disease neuropathology with experts on proteolysis in a variety of other systems which may have direct or indirect bearing on the etiology and pathogenesis of Alzheimer's disease.

FOR ADDITIONAL INFORMATION, PLEASE CONTACT: Ms. Chally L. Tate, Neuroscience and Neuropsychology of Aging Program, National Institute on Aging, National Institutes of Health, Gateway Building, room 3C307, 7201 Wisconsin Avenue, Bethesda, Maryland 20892, Telephone: (301) 496-9350, FAX: (301) 496-1494.

Bernadine Healy,

Director, National Institutes of Health.

[FR Doc. 91-28887 Filed 12-2-91; 8:45 am]

BILLING CODE 4140-01-M

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

Office of the Assistant Secretary for Administration

[Docket No. N-91-3352]

Privacy Act of 1974; Computer Matching Program

AGENCY: Department of Housing and Urban Development (HUD).

ACTION: Notice of a Computer Matching Program—HUD and United States Department of Agriculture (USDA).

SUMMARY: In accordance with the Privacy Act of 1974 (5 U.S.C. 552a), as amended by the Computer Matching and Privacy Protection Act of 1988, as amended, (Pub. L. 100-503), and the Office of Management and Budget (OMB) Guidelines on the Conduct of Matching Programs (54 FR 25818 (June 19, 1989)), and OMB Bulletin 89-22, "Instructions on Reporting Computer Matching Programs to the Office of Management and Budget (OMB), congress and the Public," the Department of Housing and Urban Development (HUD) is issuing a public notice of its intent to conduct a computer matching program with the United States Department of Agriculture (USDA) to utilize a computer information system of HUD, the Credit Alert Interactive Voice Response System (CAIVRS), with USDA's debtor files. This match will allow prescreening of applicants for loans or loans guaranteed by the Federal Government to ascertain if the applicant is delinquent in paying a debt owed to or insured by the Federal Government for HUD or USDA direct or guaranteed loans.

Before granting a loan, the lending agency and/or the authorized lending institution will be able to interrogate the CAIVRS debtor file which contains the Social Security Numbers (SSNs) of HUD's delinquent debtors and defaulters and defaulted debtor records of the USDA and verify that the loan applicant is not in default or delinquent on direct or guaranteed loans of participating Federal programs of either agency. Athorized users place a telephone call to the system. The system provides a recorded message followed by a series of instructions, one of which is a requirement for the SSN of the loan applicant. The system then reports audibly whether the SSN is related to delinquent or defaulted Federal obligations for HUD or USDA direct or guaranteed loans. As a result of the information produced by this match, the authorized users may not deny, terminate, or make a final decision of any loan assistance to an applicant or take other adverse action against such applicant, until an officer or employee of such agency has independently verified such information.

DATES: *Effective Date:* Computer matching is expected to begin at least 30 days from the date this computer matching notice is published, providing no comments are received which would result in a contrary determination. It is planned to be accomplished 18 months from the beginning date.

Comments Due Date: January 2, 1992.

ADDRESSES: Interested persons are invited to submit comments regarding this notice to the Rules Docket Clerk,

Office of General Counsel, room 10276, Department of Housing and Urban Development, 451 Seventh Street, SW., Washington, DC 20410. Communications should refer to the above docket number and title. A copy of each communication submitted will be available for public inspection and copying between 7:30 a.m. and 5:30 p.m. weekdays at the above address.

As a convenience to commenters, the Rules Docket Clerk will accept brief public comments transmitted by facsimile ("FAX") machine. The telephone number of the FAX receiver is (202) 708–4337. Only public comments of six or fewer total pages will be accepted via FAX transmittal. This limitation is necessary in order to assure reasonable access to the equipment. Comments sent by FAX in excess of six pages will not be acknowledged, except that the sender may request confirmation of receipt by calling the rules Docket Clerk ((202) 708–2084. [These are not toll-free numbers.]

FOR PRIVACY ACT INFORMATION CONTACT: Jeanette Smith, Acting Departmental Privacy Act Officer, telephone number (202) 708–0050. [This is not a toll-free telephone number.]

FOR FURTHER INFORMATION FROM RECIPIENT AGENCY CONTACT: Mary Felton, Office of Assistant Secretary for Housing-Federal Housing Commissioner, Department of Housing and Urban Development, 451 7th St., SW., room 2118, Washington, DC 20410, telephone number (202) 708–1941. [This is not a toll-free number.]

FOR FURTHER INFORMATION FROM SOURCE AGENCY CONTACT: Reynaldo Gonzalez, Debt/Credit Management Coordinator, U.S. Department of Agriculture, 14th and Independence Avenue, SW., Washington, DC 20250, telephone number (202) 720–1168. [This is not a toll-free number.]

Reporting

In accordance with Public Law 100–503, the Computer Matching and Privacy Protection Act of 1988, as amended, and Office of Management and Budget Bulletin 89–22, "Instructions on Reporting Computer Matching Programs to the Office of Management and Budget (OMB), Congress and the Public;" copies of this Notice and report, in duplicate, are being provided to the Committee on Government Operations of the House and Representatives, the Committee on Governmental Affairs of the Senate, and the Office of Management and Budget.

Authority

The matching program may be conducted pursuant to Public Law 100–503, "The Computer Matching and Privacy Protection Act of 1988," as amended, and Office of Management and Budget (OMB) Circulars A–129 (Managing Federal Credit Programs) and A–70 (Policies and Guidelines for Federal Credit Programs). One of the purposes of all executive departments and agencies—including HUD—is to implement efficient management practices for Federal credit programs. OMB Circulars A–129 and A–70 were issued under the authority of the Budget and Accounting Act of 1921, as amended; the Budget and Accounting Act of 1950, as amended; the Debt Collection Act of 1982, as amended; and, the Deficit Reduction Act of 1984, as amended.

Objectives to be met by the Matching Program

The matching program will allow USDA access to a system which permits prescreening of applicants for loans or loans guaranteed by the Federal Government to ascertain if the applicant is delinquent in paying a debt owed to or insured by the Government. In addition, HUD will be provided access to USDA debtor data for prescreening purposes.

Records to be Matched

HUD will utilize its system of records entitled HUD/DEPT–2, Accounting Records. The debtor files for HUD programs involved are included in this system of records. HUD's debtor files contain information on borrowers and co-borrowers who are currently in default (at least 90 days delinquent on their loans); or who have any outstanding claims paid during the last three years on title II insured or guaranteed home mortgage loans; or individuals who have defaulted on section 312 rehabilitation loans; or individuals who have had a claim paid in the last three years on a Title I loan. For the CAIVRS match, HUD/DEPT–2, System of Records, receives its program inputs from HUD/DEPT–2, System of Records, receives its program inputs form HUD/DEPT–28, Property Improvement and Manufactured (Mobile) Home Loans—Default; HUD/DEPT–32, Delinquent/Default/Assigned Temporary Mortgage Assistance Payments (TMAP) Program; and HUD/CPD–1, Rehabilitation Loans-Delinquent/Default.

The USDA will provide HUD with debtor files contained in its system of records entitled, Applicant/Borrower or Grantee File, (USDA/FmHA–1). HUD is maintaining USDA's records only as a ministerial action on behalf of USDA, not as a part of HUD's HUD/DEPT–2 system of records. USDA's data contain information on individuals who have defaulted on their loans. The USDA will retain ownership and responsibility for their systems of records that they place with HUD. HUD serves only as a record location and routine use recipient for USDA's data.

Notice Procedures

HUD and the USDA will notify individuals at the time of application (ensuring that routine use appears on the application form) for guaranteed or direct loans that their records will be matched to determine whether they are delinquent or in default on a federal debt. HUD and the USDA will also publish notices concerning routine use disclosures in the **Federal Register** to inform individuals that a computer match may be performed to determine a loan applicant's credit status with the Federal Government.

Categories of Records/Individuals Involved

The debtor records include these data elements: SSN, claim number, program code, and indication of indebtedness. Categories of records include: records of claims and defaults, repayment agreements, credit reports, financial statements, and records of foreclosures. Categories of individuals include: Former mortgagors and purchasers of HUD-owned properties, manufactured (mobile) home and home improvement loan debtors who are delinquent or in default on their loans, and rehabilitation loan debtors who are delinquent or in default on their loans.

Period of the Match

Matching will begin at least 30 days from the date copies of the signed (by both Data Integrity Boards) computer matching agreement are sent to both Houses of Congress or at least 30 days from the date this notice is published in the **Federal Register**, whichever is later, providing no comments are received which would result in a contrary determination.

Issued at Washington, DC November 27, 1991.

Jerry R. Pierce,

Deputy Assistant Secretary for Finance and Management.

[FR Doc. 91–28978 Filed 12–2–91; 8:45 am]

BILLING CODE 4210–01–M

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[NV-010-92-4410-10]

Elko District Advisory Council Meeting

Notice is hereby given that the District Advisory Council for the Elko District, Nevada, will meet on December 18, 1991, in accordance with 43 CFR 1784.6-4. The meeting will begin at 8 a.m. and continue into the afternoon. It will be held in the District Conference Room at 3900 E. Idaho, in Elko.

The major agenda item is to discuss the draft of the Marys River Master Plan. Other agenda items will include an overview of the Marys River Reverse Exchange and a briefing on mining activities on the District.

The meeting is open to the public, and members of the public may make statements before the Council from 8:30-9 a.m. Persons wishing to make a statement to the Council should contact Lauren Mermejo at the District Office at (702) 753-0200 no later than December 16th.

Dated: November 21, 1991.

Rodney Harris,

District Manager.

[FR Doc. 91-28856 Filed 12-2-91; 8:45 am]

BILLING CODE 4310-HC-M

Office of Surface Mining Reclamation and Enforcement

Information Collection Submitted to the Office of Management and Budget for Review Under the Paperwork Reduction Act

The proposal for the collection of information listed below has been submitted to the Office of Management and Budget for approval under the provisions of the Paperwork Reduction Act (44 U.S.C. chapter 35). Copies of the proposed collection of information and related forms may be obtained by contacting the Bureau's clearance officer at the phone number listed below. Comments and suggestions on the requirements should be made directly to the bureau clearance officer and to the Office of Management and Budget, Paperwork Reduction Project (1029-0087), Washington, DC 20503, telephone 202-395-7340.

Title: Abandoned Mine Land Problem Area Description Form.

OMB approval number: 1029-0087.

Abstract: This form will be used to update the Office of Surface Mining Reclamation and Enforcement's inventory of abandoned mine lands. From this inventory, the most serious problem areas are selected for reclamation through the apportionment of funds to States and Indian tribes.

Bureau Form Number: OSM-76.

Frequency: On occasion.

Description of respondents: State Governments and Indian Tribes.

Estimated completion time: 2 hours.

Annual responses: 1300.

Annual burden hours: 3250.

Bureau clearance officer: Andrew F. DeVito, 202-343-5150.

Dated: November 15, 1991.

John P. Mosesso,

Chief, Division of Technical Services.

[FR Doc. 91-28857 Filed 12-2-91; 8:45 am]

BILLING CODE 4310-05-M

DEPARTMENT OF JUSTICE

Aceto Agricultural Chemicals Corp. et al; Consent Decree Brought Under the Comprehensive Environmental Response, Compensation, and Liability Act and the Resource Conservation and Recovery Act

In accordance with Departmental Policy, 28 CFR 50.7, notice is hereby given that a consent decree in *United States* v. *Aceto Agricultural Chemicals Corp., et al.*, Civil Action No. 87-21-W, was lodged with the United States District Court for the Southern District of Iowa on November 20, 1991. This Consent Decree resolves a Complaint filed by the United States against the following defendants: Aceto Agricultural Chemicals Corporation, Ciba-Geigy Corporation, Mobil Oil Corporation, The Dow Chemical Company, Farnam Companies, Incorporated, Mobay Corporation, Platte Chemical Company, and Velsicol Corporation, pursuant to section 107 of the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), 42 U.S.C. 9607, and section 7003 of the Resource Conservation and Recovery Act, 42 U.S.C. 6973.

The United States Department of Justice brought this action on behalf of the U.S. Environmental Protection Agency seeking recovery of costs incurred in response to contamination at the Aidex Corporation's former pesticide formulating site in Council Bluffs, Iowa. The United States has agreed to settle this case in the amount of $11,165,188. This amount does not include costs that may be incurred as a result of the possibility that there may be a need to decontaminate buildings still located on the site. Those buildings are now being tested to determine the extent of contamination, if any.

The Department of Justice will accept written comments relating to this proposed Consent Decree for thirty (30) days from the date of publication of this notice. Please address comments to the Assistant Attorney General, Environment and Natural Resources Division, Department of Justice, P.O. Box 7611, Ben Franklin Station, Washington, DC 20044 and refer to *United States* v. *Aceto Agricultural Chemicals Corp., et al.*, DOJ#90-11-2-99.

Copies of the proposed Consent Decree may be examined at the Office of the United States Attorney, Southern District of Iowa, 115 U.S. Courthouse, East First and Walnut Streets, Des Moines, Iowa 50309, and at the U.S. Environmental Protection Agency, Office of the Regional Counsel, Region VII, 756 Minnesota Avenue, Kansas City, Kansas 66101. Copies of the proposed Consent Decree may also be examined at the Environmental Enforcement Section Document Center, 601 Pennsylvania Avenue, NW., Box 1097, Washington, DC 20004, (202) 347-7829. A copy of the proposed Consent Decree may be obtained in person or by mail from the Document Center. When requesting a copy of the Consent Decree, please enclose a check in the amount of $9.25 payable to the "Consent Decree Library."

Barry M. Hartman,

Acting Assistant Attorney General, Environment and Natural Resources Division.

[FR Doc. 91-28963 Filed 12-2-91, 8:45 am]

BILLING CODE 4410-01-M

D'Addario Industries, Inc., et al.; Lodging of Consent Decree Pursuant to the Clean Air Act

In accordance with Departmental policy, as set forth in 28 CFR 50.7, notice is hereby given that a proposed consent decree in *United States* v. *D'Addario Industries, Inc., et al.*, Civil Action No. B-89-218 (JAC), has been lodged with the United States District Court for the District of Connecticut on November 20, 1991. The proposed consent decree concerns alleged violations of the Clean Air Act and the National Emission Standard for Hazardous Air Pollutants for asbestos, 40 CFR part 61, subpart M, at two facilities in Bridgeport, Connecticut, and requires the defendants to pay a civil penalty and comply with certain injunctive provisions.

The United States Department of Justice will receive comments relating to the proposed consent decree for a period of thirty (30) days from the date of this publication. Comments should be addressed to the Assistant Attorney

General for the Environment and Natural Resources Division, Department of Justice, P.O. Box 7611, Ben Franklin Station, Washington, DC 20044, and should refer to *United States* v. *D'Addario Industries, Inc., et al.*, DJ 90–5–2–1–1270.

The proposed consent decree may be examined at the Office of the United States Attorney, District of Connecticut, U.S. District Courthouse, 141 Church Street, New Haven, Connecticut 06510, and at the Region I Office of the Environmental Protection Agency, One Congress Street, Boston, Massachusetts. A copy of the proposed consent decree and attachments can be obtained in person or by mail at the Environmental Enforcement Section Document Center, 601 Pennsylvania Avenue, NW, Box 1097, Washington, DC 20004, (202) 347–2072. In requesting a copy, please enclose a check in the amount of $6.25 (25 cents per page reproduction costs) payable to the Consent Decree Library.

John C. Cruden,

Chief, Environmental Enforcement Section.

[FR Doc. 91–28964 Filed 12–2–91; 8:45 am]

BILLING CODE 4410-01-M

Entrada Industries et al.; Lodging of Final Judgment by Consent Pursuant to the Comprehensive Environmental Response, Compensation, and Liability Act

In accordance with Departmental policy, 28 CFR 50.7, and section 122 (d) and (i) of CERCLA, 42 U.S.C. 9622 (d) and (i), notice is hereby given that on November 19, 1991, a consent decree in *United States* v. *Entrada Industries, et al.*, Civil Action No. 91C–1194S, was lodged with the United States District Court for the District of Utah.

The complaint filed by the United States at the time of lodging the consent decree alleges, under sections 106 and 107 of CERCLA, 42 U.S.C. 9606 and 9607, that the defendants, Entrada Industries, Inc., Mountain Fuel Supply Co., Inc., and Questar Corporation (the "Settlors") are liable for an injunction and response costs incurred by the United States in response to the release or threat of release of hazardous substances at the Wasatch Chemical Superfund Site, in Salt Lake City, Utah (the "Site"). The complaint further states that the defendants are past or present owners of the Site.

In the complaint, the United States, on behalf of the Environmental Protection Agency, requests a judgment against the defendants jointly and severally for implementation of the groundwater remedy selected in EPA's Record of Decision ("ROD") dated September 28, 1990, which provides for in situ vitrification of contaminated sludges and soils and pumping, treating and monitoring contaminated groundwater; reimbursement of over $400,000 in past response costs under section 107(a) of CERCLA, 42 U.S.C. 9607(a); and a determination under section 113(g)(2) of CERCLA, 42 U.S.C. 9613(g)(2), that any finding of liability would be binding in any subsequent action for further response costs or damages.

In the consent decree, the Settlors have agreed, *inter alia*, to implement the remedy selected in the ROD and to pay $418,956.73 in past costs to the Hazardous Substances Trust Fund; to pay costs of oversight and operation and maintenance of the remedy; and to perform additional work, if any. The Settlors have also agreed to review, periodically, the remedial action to ensure that human health and the environment are being protected by the remedial action being implemented. The State of Utah participated in the negotiations with the Settlors, and is a party to the consent decree.

The Department of Justice will receive comments relating to the proposed consent decree for a period of thirty days from the date of publication of this notice. Comments should be addressed to the Acting Assistant Attorney General, Environment and Natural Resources Division, Department of Justice, Washington, DC 20530, and should refer to *United States* v. *Entrada Industries, et al.*, DOJ Ref. No. 90–11–2–691. The proposed consent decree may be examined at the office of the United States Attorney, District of Utah, 350 South Main Street, Salt Lake City, Utah. Copies of the consent decree may also be examined and obtained by mail at the Environmental Enforcement Section Document Center, 601 Pennsylvania Ave., NW., Box 1097, Washington, DC 20004 (202–347–7829). When requesting a copy of the consent decree by mail, please enclose a check in the amount of $60.00 (twenty-five cents per page reproduction costs) payable to the "Consent Decree Library."

Barry M. Hartman,

Acting Assistant Attorney General, Environment and Natural Resources Division.

[FR Doc 91–28965 Filed 12–2–91; 8:45 am]

BILLING CODE 4410-01-M

Motorola, et al.; Lodging of Consent Decree Pursuant to CERCLA

In accordance with the policy of the Department of Justice, 28 CFR 50.7, and pursuant to section 122(d)(2) of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), 42 U.S.C. 9622(d)(2), notice is hereby given that a proposed Partial Consent Decree in *United States and State of Arizona* v. *Motorola, et al.*, Civ. No. 91–1835–PHX–SMM, was lodged on November 19, 1991, with the United States District Court for the District of Arizona. That action was brought against defendants pursuant to CERCLA for releases of hazardous substances that contaminated groundwater in the northern portion of the Indian Bend Wash site in Scottsdale, Arizona.

Under this Consent Decree, three companies, a local water supplier, and the City of Scottsdale agree to implement the remedial action selected by the Environmental Protection Agency ("EPA") pertaining to cleanup of contaminated groundwater in the Middle and Lower Alluvium Units beneath the northern portion of the site. This work will be performed under the oversight of EPA. Under this Consent Decree, the settling companies will design and build a groundwater treatment plant to treat the contaminated groundwater to acceptable standards. The plant will be turned over to the City of Scottsdale. The companies will pay the City's operation and maintenance costs of the plant. The treated water will either be directly used by the City in its municipal water supply system, reinjected into the ground, or accepted by the Salt River Project into its surface water canals. In addition, the companies will reimburse EPA and the State of Arizona for costs incurred in overseeing the companies' work and will reimburse the State for a portion of the State's past response costs. Further investigation is continuing at the site regarding the groundwater in the Upper Alluvium Unit and in the soils.

The Department of Justice will receive comments relating to the proposed Consent Decree for a period of 30 days from the date of this publication. Comments should be addressed to the Assistant Attorney General of the Environment and Natural Resources Division, Department of Justice, Washington, DC 20530. All comments should refer to *United States* v. *Motorola, et al. D.J. Ref. 90–11–2–413.*

The proposed consent decree may be examined at the office of the United States Attorney, 4000 United States Courthouse, 230 North First Avenue, Phoenix, Arizona 85025; at the Region IX office of the Environmental Protection Agency, 75 Hawthorne Street, San Francisco, California 94103; and at the

Environmental Enforcement Section Document Center, 601 Pennsylvania Avenue, NW, Box 1097, Washington, DC 20004, 202–347–2072. A copy of the proposed consent decree may be obtained in person or by mail from the Document Center. In requesting a copy, please enclose a check in the amount $44.50 for the decree plus its attachments (25 cents per page reproduction costs) payable to the Consent Decree Library. When requesting a copy, please refer to *United States* v. *Motorola, et al.*, D.J. Ref. 90–11–2–413.

Barry M. Hartman,

Acting Assistant Attorney General, Environment and Natural Resources Division.

[FR Doc. 91–28966 Filed 12–2–91; 8:45 am]

BILLING CODE 4410-01-M

DEPARTMENT OF LABOR

Office of the Secretary

Agency Recordkeeping/Reporting Requirements Under Review by the Office of Management and Budget (OMB)

Background

The Department of Labor, in carrying out its responsibilities under the Paperwork Reduction Act (44 U.S.C. chapter 35), considers comments on the reporting/recordkeeping requirements that will affect the public.

List of Recordkeeping/Reporting Requirements Under Review

As necessary, the Department of Labor will publish a list of the Agency recordkeeping/reporting requirements under review by the Office of Management and Budget (OMB) since the last list was published. The list will have all entries grouped into new collections, revisions, extensions, or reinstatements. The Departmental Clearance Officer will, upon request, be able to advise members of the public of the nature of the particular submission they are interested in.

Each entry may contain the following information:

The Agency of the Department issuing this recordkeeping/reporting requirement.

The title of the recordkeeping/reporting requirement.

The OMB and/or Agency identification numbers, if applicable.

How often the recordkeeping/reporting requirement is needed.

Whether small businesses or organizations are affected.

An estimate of the total number of hours needed to comply with the recordkeeping/reporting requirements and the average hours per respondent.

The number of forms in the request for approval, if applicable.

An abstract describing the need for and uses of the information collection.

Comments and Questions

Copies of the recordkeeping/reporting requirements may be obtained by calling the Departmental Clearance Officer, Kenneth A. Mills ((202) 523–5095). Comments and questions about the items on this list should be directed to Mr. Mills, Office of Information Resources Management Policy, U.S. Department of Labor, 200 Constitution Avenue, NW., room N–1301, Washington, DC 20210. Comments should also be sent to the Office of Information and Regulatory Affairs, Attn: OMB Desk Officer for (BLS/DM/ESA/ETA/OLMS/MSHA/OSHA/PWBA/VETS), Office of Management and Budget, room 3001, Washington, DC 20503 ((202) 395–6880).

Any member of the public who wants to comment on recordkeeping/reporting requirements which have been submitted to OMB should advise Mr. Mills of this intent at the earliest possible date.

New

Employment and Training Administration

Study of the Implementation of Economic Dislocation and Worker Adjustment Act.

One-time only.

State or local governments.

466 respondents; 466 total hours; 1 hr per response;

No forms.

A nationwide survey of EDWAA substate areas to provide an accurate description of the variation in organizational arrangements, programs designs and service delivery practices and to generate information for multivariate analyses of the relationships between substate practices and the types of clients served, the range of services provided, and participant outcomes.

Occupational Safety and Health Administration

New.

Occupational Exposure to Bloodborne Pathogens.

On occasion.

Businesses or other for-profit; small businesses or organizations.

400 respondents; 32 burden hours; .08 hours per response.

No forms.

The Bloodborne Pathogen standard and its information collection requirements provides protection for employees from the adverse health effects associated with occupational exposure to bloodborne pathogens. The standard requires that OSHA have access to the employers exposure control plan as well as the employee's training and medical records to ensure that employers are complying with the disclosure provisions of the bloodborne pathogen standard.

Information Collection Activity	Initial	Proposed total burden hours recurring
Availability	32	32
Records Access and Transfer	0	0
Total	32	32

Extension

Employment and Training Administration

Administrative Procedures—20 CFR 601 including Form MA 87.

1205–0222.

MA 87.

As needed.

State and local governments.

53 respondents; 53 total hours; 1 hr. per response.

1 form.

Requires States to submit copies of their unemployment insurance laws for approval by the Secretary of Labor, as well as all relevant State materials which allow the Secretary to make findings required by the Internal Revenue Code, Social Security Act, and Wagner-Peyser Act.

Signed at Washington, DC this 26th day of November, 1991.

Kenneth A. Mills,

Departmental Clearance Officer.

[FR Doc. 91–28924 Filed 12–2–91; 8:45 am]

BILLING CODE 4510-22-M

Occupational Safety and Health Administration

Maryland State Standards; Approval

1. Background

Part 1953 of title 29, Code of Federal Regulations, prescribes procedures under section 18 of the Occupational Safety and Health Act of 1970 (hereinafter called the Act) by which the Regional Administrator for Occupational Safety and Health (hereinafter called the Regional Administrator) under a delegation of authority from the Assistant Secretary

of Labor for Occupational Safety and Health (hereinafter called the Assistant Secretary) (29 CFR 1953.4), will review and approve standards promulgated pursuant to a State plan which has been approved in accordance with section 18(c) of the Act and 29 CFR part 1902. On July 5, 1973, notice was published in the **Federal Register** (38 FR 17834) of the approval of the Maryland State plan and the adoption of subpart 0 to part 1952 containing the decision.

The Maryland State Plan provides for the adoption of all Federal standards as State standards after comments and public hearing. Section 1952.210 of subpart 0 sets forth the State's schedule for the adoption of Federal standards. By letter dated September 25, 1991, from Commissioner Henry Koellein, Jr., Maryland Division of Labor and Industry, to Linda R. Anku, Regional Administrator, and incorporated as part of the plan, the State submitted State standards identical to: 29 CFR 1910.120(a)(3) and (e)(9), subpart Z, pertaining to corrections and revisions to the Hazardous Waste Operations and Emergency Response Standard for General Industry as published in the **Federal Register** of April 18, 1991 (56 FR 15832). This standard is contained in COMAR 09.12.31. Maryland occupational safety and health standards were promulgated after a public hearing on May 8, 1991. This standard became effective on September 30, 1991.

2. Decision

Having reviewed the State submissions in comparison with the Federal standards, it has been determined that the State standards are identical to the Federal standards and, accordingly, are approved.

3. Location of the Supplement for Inspection and Copying

A copy of the standards supplement, along with the approved plan, may be inspected and copied at the following locations during normal business hours: Office of the Regional Administrator, 3535 Market Street, suite 2100, Philadelphia, Pennsylvania 19104; Office of the Commissioner of Labor and Industry, 501 St. Paul Place, Baltimore, Maryland 21202-2272; and the Occupational Safety and Health Administration, Office of State Programs, room N-3700, Third Street and Constitution Avenue, NW., Washington DC 20210.

4. Public Participation

Under 29 CFR 1953.2(c), the Assistant Secretary may prescribe alternative procedures to expedite the review process or for other good cause which may be consistent with applicable laws. The Assistant Secretary finds that good cause exists for not publishing the supplement to the Maryland State plan as a proposed change and making the Regional Administrator's approval effective upon publication for the following reasons:

a. The standard is identical to the Federal standard which was promulgated in accordance with Federal law including meeting requirements for public participation.

b. The standard was adopted in accordance with the procedural requirements of State law and further participation would be unnecessary.

This decision is effective December 3, 1992.

(Sec. 18, Pub. L. 91-596, 84 Stat. 1608 (29 U.S.C. 667))

Signed at Philadelphia, Pennsylvania, this 21st day of October 1991.

Linda R. Anku,

Regional Administrator.

[FR Doc. 91-28923 Filed 12-2-91; 8:45 am]

BILLING CODE 4510-26-M

NATIONAL SCIENCE FOUNDATION

International Programs Review Panel; Meeting

In accordance with the Federal Advisory Committee Act (Pub. L. 92-463, as amended), the National Science Foundation announces the following meeting:

Name: International Programs Review Panel.

Date and Time: December 16-17, 1991; 8:30 a.m. to 5 p.m.

Place: 1110 Vermont Avenue, NW., room 500A, Washington, DC 20550.

Type of Meeting: Closed.

Contact Person: Janice Cassidy, Program Manager, 1110 Vermont Avenue, NW., room 501, Washington, DC 20550. Telephone: (202) 653-1214.

Purpose of Meeting: To provide advice and recommendations concerning applications submitted to NSF for financial support.

Agenda: To review and evaluate applications for JSPS and STA Postdoctoral Fellowships in Japan.

Reason for Closing: The applications being reviewed include information of a proprietary or confidential nature, including technical information; financial data, such as salaries; and personal information concerning individuals associated with the proposals. These matters are within exemptions 4 and 6 of 5 U.S.C. 552b.(c)(4) and (6) the Government in the Sunshine Act.

Dated: November 26, 1991.

M. Rebecca Winkler,

Committee Management Officer.

[FR Doc. 91-28881 Filed 12-2-91; 8:45 am]

BILLING CODE 7555-01-M

NUCLEAR REGULATORY COMMISSION

Advisory Committee on Reactor Safeguards, Subcommittee on Planning and Procedures; Meeting

The ACRS Subcommittee on Planning and Procedures will hold a meeting on December 11, 1991, room P-422, 7920 Norfolk Avenue, Bethesda, MD.

The entire meeting will be open to public attendance.

The agenda for the subject meeting shall be as follows:

Wednesday, December 11, 1991—4:30 p.m. until 6:00 p.m.

The Subcommittee will discuss anticipated ACRS workload and items proposed for consideration by the full Committee. Implementation of Committee plans to resolve Key Technical Issues related to future nuclear power plants, and revised committee practices and procedures will also be discussed, as appropriate.

Oral statements may be presented by members of the public with the concurrence of the Subcommittee Chairman; written statements will be accepted and made available to the Committee. Recordings will be permitted only during those portions of the meeting when a transcript is being kept, and questions may be asked only by members of the Subcommittee, its consultants, and staff. Persons desiring to make oral statements should notify the ACRS staff member named below as far in advance as is practicable so that appropriate arrangements can be made.

Further information regarding topics to be discussed, the scheduling of sessions open to the public, whether the meeting has been cancelled or rescheduled, the Chairman's ruling on requests for the opportunity to present oral statements and the time allotted therefore can be obtained by a prepaid telephone call to the Designated Federal Official, Mr. Raymond F. Fraley (telephone 301/492-4516 between 7:30 a.m. and 4:15 p.m., e.s.t. Persons planning to attend this meeting are urged to contact the above named individual one or two days before the scheduled meeting to be advised of any changes in schedule, etc., that may have occurred.

Dated: November 26, 1991.

John C. Hoyle,

Advisory Committee Management Officer.

[FR Doc. 91-28906 Filed 12-2-91; 8:45 am]

BILLING CODE 7590-01-M

Advisory Committee on Nuclear Waste; Meeting

The Advisory Committee on Nuclear Waste (ACNW) will hold its 38th meeting on December 18-19, 1991, 8:30 a.m.—5 p.m., room P-110, 7920 Norfolk Avenue, Bethesda, MD each day. Portions of this meeting will be closed to discuss information the release of which would represent a clearly unwarranted invasion of personal privacy 5 U.S.C. 552b(c)(6). Notice of this meeting was published previously in the **Federal Register** on Monday, November 25, 1991 (56 FR 59304).

The agenda for the subject meeting shall be as follows:

A. Review the Staff Technical Position on the Identification of Fault Displacement and Seismic Hazards at a Geologic Repository.

B. Discuss the results of a Working Group meeting on concerns related to Faulting and Seismic Investigations of a proposed HLW repository site.

C. Discuss items of mutual interest with the Commission.

D. Election of Committee officers for CY 1992 (Open/Closed). This session will be closed as necessary to discuss information the release of which would represent a clearly unwarranted invasion of personal privacy.

E. Develop a response to Chairman Selin on a systems analysis approach to the storage of spent fuel.

F. Prepare a program plan for the next four months.

G. Prepare a report on Quaternary dating methods for volcanic features and materials.

H. Discuss anticipated and proposed Committee activities, future meeting agenda, administrative, and organizational matters, as appropriate. Also, discuss matters and specific issues that were not completed during previous meetings as time and availability of information permit.

Procedures for the conduct of and participation in ACNW meetings were published in the **Federal Register** on June 6, 1988 (53 FR 20699). In accordance with these procedures, oral or written statements may be presented by members of the public, recordings will be permitted only during those portions of the meeting when a transcript is being kept, and questions may be asked only by members of the Committee, its consultants, and staff. The office of the ACRS is providing staff support for the ACNW. Persons desiring to make oral statements should notify the Executive Director of the office of the ACRS as far in advance as practical so that appropriate arrangements can be made to allow the necessary time during the meeting for such statements. Use of still, motion picture, and television cameras during this meeting may be limited to selected portions of the meeting as determined by the ACNW Chairman. Information regarding the time to be set aside for this purpose may be obtained by a prepaid telephone call to the Executive Director of the office of the ACRS, Mr. Raymond F. Fraley (telephone 301/492-4516), prior to the meeting. In view of the possibility that the schedule for ACNW meetings may be adjusted by the Chairman as necessary to facilitate the conduct of the meeting, persons planning to attend should check with the ACRS Executive Director or call the recording (301/492-4600) for the current schedule if such rescheduling would result in major inconvenience.

Dated: November 27, 1991.

John C. Hoyle,

Advisory Committee Management Officer.

[FR Doc. 91-28907 Filed 12-2-91; 8:45 am]

BILLING CODE 7590-01-M

State of Maine: Staff Assessment of Proposed Agreement Between the Nuclear Regulatory Commission and the State of Maine

AGENCY: Nuclear Regulatory Commission.

ACTION: Notice of proposed agreement with the State of Maine.

SUMMARY: The U.S. Nuclear Regulatory Commission is publishing for public comment the NRC staff assessment of a proposed agreement received from the Governor of the State of Maine for the assumption of certain of the Commission's regulatory authority pursuant to section 274 of the Atomic Energy Act of 1954, as amended. Comments are requested on the public health and safety aspects of the proposal.

Exemptions from the Commission's regulatory authority, which would implement this proposed agreement, have been published in the **Federal Register** and codified as part 150 of the Commission's regulations in title 10 of the Code of Federal Regulations.

DATES: Comments must be received on or before January 2, 1992.

ADDRESSES: Submit comments to the Chief, Regulatory Publications Branch, Division of Freedom of Information and Publications Services, Office of Administration, Washington, DC 20555. Comments may also be delivered to 7920 Norfolk Avenue, Bethesda, Maryland from 7:30 a.m. to 4:15 p.m. Monday through Friday. Copies of comments received by NRC may be examined at the NRC Public Document Room, 2120 L Street, NW. (Lower Level), Washington, DC. A copy of the proposed agreement, program narrative, including the referenced appendices, applicable State legislation and Marine regulations, is available for public inspection in the NRC's Public Document Room, 2120 L Street, NW. (Lower Level), Washington, DC, telephone: (202) 634-3273.

FOR FURTHER INFORMATION CONTACT: Kathleen N. Schneider, State Programs, U.S. Nuclear Regulatory Commission, Washington, DC 20555, telephone: 301-492-0320.

SUPPLEMENTARY INFORMATION: Assessment of Proposed Maine Program to Regulate Certain Radioactive Materials pursuant to section 274 of the Atomic Energy Act of 1954, as amended (the Act).

The Commission has received a proposal from the Governor of Maine for the State to enter into an agreement with the NRC whereby the NRC would relinquish and the State would assume certain regulatory authority pursuant to section 274 of the Act.

Section 274e of the Act requires that the terms of the proposed agreement be published for public comment once each week for four consecutive weeks. Accordingly, this notice will be published four times in the **Federal Register**.

I. Background

A. Section 274 of the Act provides a mechanism whereby the NRC may transfer to the States certain regulatory authority over agreement materials [1] when a State desires to assume this authority and the Governor certifies that the State has an adequate regulatory program, and when the Commission finds that the State's program is compatible with that of the NRC and is adequate to protect the public health and safety. Section 274g directs the Commission to cooperate with the States in the formulation of standards for protection against radiation hazards

[1] A. Byproduct materials as defined in 11e.(1)
B. Byproduct materials as defined in 11e.(2)
C. Source materials; and
D. Special nuclear materials in quantities not sufficient to form a critical mass

to assure that State and Commission programs for radiation protection will be coordinated and compatible. Further, section 274j provides that the Commission shall periodically review such agreements and actions taken by the States under the agreements to ensure compliance with the provisions of this section.

B. In a letter dated March 5, 1990, Governor John P. McKernan, Jr. of the State of Maine requested that the Commission enter into an agreement with the State pursuant to section 274 of the Act. The Governor certified that the State of Maine has a program for control of radiation hazards which is adequate to protect the public health and safety with respect to the materials within the State covered by the proposed agreement, and that the State of Maine desires to assume regulatory responsibility for such materials. The text of the proposed agreement is shown in appendix A to this document.

The specific authority requested is for (1) byproduct material as defined in section 11e.(1) of the Act, (2) source material, and (3) special nuclear material in quantities not sufficient to form a critical mass. The State does not wish to assume authority over (1) land disposal of source, byproduct and special nuclear material received from other persons; and (2) uranium recovery activities (byproduct material is defined in section 11e.(2)). The State, however, reserves the right to apply at a future date to NRC for an amended agreement to assume authority in these areas. The nine articles of the proposed agreement—

Lists the materials covered by the agreement.

Lists the Commission's continued authority and responsibility for certain activities.

Allows for future amendment of the agreement.

Allows for certain regulatory changes by the Commission.

References the continued authority of the Commission for common defense and security for safeguard purposes.

Pledges the best efforts of the Commission and the State to achieve coordinated and compatible programs.

Recognizes reciprocity of licenses issued by the respective agencies.

Sets forth criteria for termination or suspension of the agreement.

Specifies the effective date of the agreement.

C. Maine Radiation Protection Act, sections 671 through 690, the enabling statute for the Maine Department of Human Services, authorizes the Department to issue licenses to, and perform inspections of, users of radioactive materials under the proposed agreement and otherwise carry out a total radiation control program. Maine regulations for radiation protection were adopted on January 1, 1986, with revisions dated January 1, 1988 and December 1, 1990, under authority of the enabling statute and provide standards, licensing, inspection, enforcement and administrative procedures for agreement and non-agreement materials. In addition, editorial revisions recommended by NRC are presently under consideration in Maine and are expected to be finalized in November 1991. Pursuant to Maine's regulations, section C.19, the regulations will apply to agreement materials on the effective date of the agreement. In addition to the material covered under the proposed agreement, the regulations provide for the State to license and inspect users of naturally-occurring and accelerator-produced radioactive materials.

D. The NRC staff assessment finds the proposed Maine program will provide adequately for public health and safety.

II. NRC Staff Assessment of the Proposed Maine Program for Control of Agreement Materials

Reference: Criteria for Guidance of States and NRC in Discontinuance of NRC Regulatory Authority and Assumption Thereof by States Through Agreement.[2]

Objectives

1. *Protection.* A State regulatory program shall be designed to protect the health and safety of the people against radiation hazards.

Based upon the analysis of the State's proposed regulatory program, the staff believes the Maine proposed regulatory program for agreement materials is adequately designed to protect the health and safety of the public against radiation hazards.

Reference: Maine Program Statement, Application for Agreement State Status.

Radiation Protection Standards

2. *Standards.* The State regulatory program shall adopt a set of standards for protection against radiation which shall apply to byproduct, source and special nuclear materials in quantities not sufficient to form a critical mass.

Statutory authority to formulate and promulgate rules for controlling exposure to sources of radiation is contained in the enabling statute. In accordance with that authority, the State adopted radiation control regulations on January 1, 1986, and with revisions dated January 1, 1988, and December 1, 1990, which include radiation protection standards which would apply to byproduct, source and special nuclear materials in quantities not sufficient to form a critical mass upon the effective date of an agreement between the State and the Commission pursuant to Section 274b of the Atomic Energy Act of 1954, as amended. In addition, editorial revisions recommended by NRC are presently under consideration by the State and are expected to be finalized in November 1991.

Reference: State of Maine Rules Relating to Radiation Protection Parts A, B, C, D, E, G, J, K, L, Letter dated October 14, 1991.

3. *Uniformity in Radiation Standards.* It is important to strive for uniformity in technical definitions and terminology, particularly as related to such things as units of measurement and radiation dose. There shall be uniformity on maximum permissible doses and levels of radiation and concentrations of radioactivity, as fixed by 10 CFR part 20 of the NRC regulations based on officially approved radiation protection guides.

Technical definitions and terminology contained in the Maine Radiation Control Regulations including those related to units of measurement and radiation doses are uniform with those contained in 10 CFR part 20.

Reference: State of Maine Rules Relating to Radiation Protection Sections A.2, D.2, E.3, G.2, K.3, L.2.

4. *Total Occupational Radiation Exposure.* The regulatory authority shall consider the total occupational radiation exposure of individuals, including that from sources which are not regulated by it.

The Maine regulations cover all sources of radiation within the State's jurisdiction and provide for consideration of the total radiation exposure of individuals from all sources of radiation in the possession of a licensee or registrant.

Reference: State of Maine Rules Relating to Radiation Protection Sections D.2 to D.7.

5. *Surveys, Monitoring.* Appropriate surveys and personnel monitoring under the close supervision of technically competent people are essential in achieving radiological protection and shall be made in determining compliance with safety regulations.

The Maine requirements for surveys to evaluate potential exposures from

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[2] NRC Statement of Policy published in the **Federal Register** January 23, 1981 (46 FR 7540–7546), a correction was published July 16, 1981 (46 FR 36969) and a revision of Criterion 9 published in the **Federal Register** July 21, 1983 (48 FR 33376).

sources of radiation and the personnel monitoring requirements are uniform with those contained in 10 CFR part 20.

References: State of Maine Rules Relating to Radiation Protection Sections D.9, D.10 and D.15.

6. *Labels, Signs, Symbols.* It is desirable to achieve uniformity in labels, signs, and symbols, and the posting thereof. However, it is essential that there be uniformity in labels, signs, and symbols affixed to radioactive products which are transferred from person to person.

The prescribed radiation labels, signs and symbols are uniform with those contained in 10 CFR parts 20, 30 thru 32 and 34. The Maine posting requirements are also uniform with those of 10 CFR part 20.

References: State of Maine Rules Relating to Radiation Protection Sections C.6.E, C.6.F, C.11.D, D.11 and D.12.

7. *Instruction.* Persons working in or frequenting restricted areas shall be instructed with respect to the health risks associated with exposure to radioactive materials and in precautions to minimize exposure. Workers shall have the right to request regulatory authority inspections as per 10 CFR 19.16 and to be represented during inspections as specified in 10 CFR 19.14.

The Maine regulations contain requirements for instructions and notices to workers that are uniform with those of 10 CFR part 19.

Reference: State of Maine Rules Relating to Radiation Protection Section J.

8. *Storage.* Licensed radioactive material in storage shall be secured against unauthorized removal.

The Maine regulations contain a requirement for security of stored radioactive material.

Reference: State of Maine Rules Relating to Radiation Protection Section D.14.

9. *Radioactive Waste Disposal.* (a) Waste disposal by material users. The standards for the disposal of radioactive materials into the air, water and sewer, and burial in the soil shall be in accordance with 10 CFR part 20. Holders of radioactive material desiring to release or dispose of quantities or concentrations of radioactive materials in excess of prescribed limits shall be required to obtain special permission from the appropriate regulatory authority.

Requirements for transfer of waste for the purpose of ultimate disposal at a land disposal facility (waste transfer and manifest system) shall be in accordance with 10 CFR part 20.

The waste disposal standards shall include a waste classification scheme and provisions for waste form, applicable to waste generators, that is equivalent to that contained in 10 CFR part 61.

(b) Land Disposal of waste received from other persons. The State shall promulgate regulations containing licensing requirements for land disposal of radioactive waste received from other persons which are compatible with the applicable technical definitions, performance objectives, technical requirements and applicable supporting sections set forth in 10 CFR part 61. Adequate financial arrangements (under terms established by regulation) shall be required of each waste disposal site licensee to ensure sufficient funds for decontamination, closure and stabilization of a disposal site. In addition, Agreement State financial arrangements for long-term monitoring and maintenance of a specific site must be reviewed and approved by the Commission prior to relieving the site operator of licensed responsibility (section 151(a)(2), Pub. L. 97–425).

The Maine regulations contain provisions relating to the disposal of radioactive materials into the air, water and sewer and burial in soil which are essentially uniform with those of 10 CFR part 20. Waste transfer and manifest system requirements for transfer of waste for ultimate disposal at a land disposal facility are included in the Maine regulations. The waste disposal requirements include a waste classification scheme and provisions for waste form equivalent to that in 10 CFR part 61.

Maine does not plan on seeking authority for the regulation of land disposal of source, byproduct and special nuclear material received from other persons.

References: State of Maine Rules Relating to Radiation Protection Sections D.7, and D.16 to D.26.

10. *Regulations Governing Shipment of Radioactive Materials.* The State shall to the extent of its jurisdiction promulgate regulations applicable to the shipment of radioactive materials, such regulations to be compatible with those established by the U.S. Department of Transportation and other agencies of the United States whose jurisdiction over interstate shipment of such materials necessarily continues. State regulations regarding transportation of radioactive materials must be compatible with 10 CFR part 71.

The Maine regulations are uniform with those contained in NRC regulations 10 CFR part 71.

References: State of Maine Rules Relating to Radiation Protection Section L.

11. *Records and Reports.* The State regulatory program shall require that holders and users of radioactive materials (a) maintain records covering personnel radiation exposures, radiation surveys, and disposals of materials; (b) keep records of the receipt and transfer of the materials; (c) report significant incidents involving the materials, as prescribed by the regulatory authority; (d) make available upon request of a former of a former employee a report of the employee's exposure to radiation; (e) at request of an employee advise the employee of his or her annual radiation exposure; and (f) inform each employee in writing when the employee has received radiation exposure in excess of the prescribed limits.

The Maine regulations require the following records and reports of the licensees and registrants:

(a) Records covering personnel radiation exposures, radiation surveys, and disposals of materials.

(b) Records of receipt and transfer of materials.

(c) Reports concerning incidents involving radioactive materials.

(d) Reports to former employees of their radiation exposure.

(e) Reports to employees of their annual radiation exposure.

(f) Reports to employees of radiation exposure in excess of prescribed limits.

Reference: State of Maine Rules Relating to Radiation Protection Sections A. 4, D.27, D.29, D.30, and J.4.

12. *Additional Requirements and Exemptions.* Consistent with the overall criteria here enumerated and to accommodate special cases and circumstances, the State regulatory authority shall be authorized in individual cases to impose additional requirements to protect health and safety, or to grant necessary exemptions which will not jeopardize health and safety.

The Maine Radiation Control Program is authorized to impose upon any licensee or registrant by rule, regulation, or order such requirements in addition to those established in the regulations as it deems appropriate or necessary to minimize danger to public health and safety or property.

Reference: State of Maine Rules Relating to Radiation Protection Section A.7.

The Department may also grant such exemptions from the requirements of the regulations as it determines are authorized by law and will not result in

undue hazard to public health and safety or property.

Reference: State of Maine Rules Relating to Radiation Protection Section A.3.

Prior Evaluation of Uses of Radioactive Materials

13. *Prior Evaluation of Hazards and Uses, Exceptions.* In the present state of knowledge, it is necessary in regulating the possession and use of byproduct, source and special nuclear materials that the State regulatory authority require the submission of information on, and evaluation of, the potential hazards and the capability of the user or possessor prior to his receipt of the materials. This criterion is subject to certain exceptions and to continuing reappraisal as knowledge and experience in the atomic energy field increase. Frequently there are, and increasingly in the future there may be, categories of materials and uses as to which there is sufficient knowledge to permit possession and use without prior evaluation of the hazards and the capability of the possessor and user. These categories fall into two groups—those materials and uses which may be completely exempt from regulatory controls, and those materials and uses in which sanctions for misuse are maintained without pre-evaluation of the individual possession or use. In authorizing research and development or other activities involving multiple uses of radioactive materials, where an institution has people with extensive training and experience. The State regulatory authority may wish to provide a means for authorizing broad use of materials without evaluating each specific use.

Prior to the issuance of a specific license for the use of radioactive materials, the Maine Radiation Control Program will require the submission of information on, and will make an evaluation of, the potential hazards of such uses, and the capability of the applicant.

References: State of Maine Rules Relating to Radiation Protection Sections C.7 and C.17 and the Maine Program Statement.

Provision is made for the issuance of general licenses for byproduct, source and special nuclear materials in situation where prior evaluation of the licensee's qualifications, facilities, equipment and procedures is not required. The regulations grant general licenses under the same circumstances as those under which general licenses are granted in the Commission's regulations.

References: State of Maine Rules Relating to Radiation Protection Sections C.5 and C.6.

The Maine regulations contain provisions for exempting of certain source and other radioactive materials and devices containing radioactive materials. These exemptions, for materials covered by the agreement, are the same as those granted by NRC regulations.

References: State of Maine Rules Relating to Radiation Protection Sections C.2 and C.3.

14. *Evaluation Criteria.* In evaluating a proposal to use radioactive materials, the regulatory authority shall determine the adequacy of the applicant's facilities and safety equipment, his training and experience in the use of the materials for the purpose requested, and his proposed administrative controls. States should develop guidance documents for use by license applicants. This guidance should be consistent with NRC licensing and regulatory guides for various categories of licensed activities.

In evaluating a proposal to use agreement materials, the Maine Radiation Control Program will determine that:

(1) The applicant is qualified by reason of training and experience to use the material in question for the purpose requested in accordance with the regulations in such a manner as to minimize danger to public health and safety or property;

(2) The applicant's proposed equipment, facilities, and procedures are adequate to minimize danger to public health and safety or property; and.

(3) The issuance of the license will not be inimical to the health and safety of the public.

Other special requirements for the issuance of specific licenses are contained in the regulations.

References: State of Maine Rules Relating to Radiation Protection Sections C.8 to C.11 and the Maine Program Statement.

15. *Human Use.* The use of radioactive materials and radiation on or in humans shall not be permitted except by properly qualified persons (normally licensed physicians) possessing prescribed minimum experience in the use of radioisotopes or radiation.

The Maine regulations require that the use of radioactive materials (including sealed sources) on or in humans shall be by a physician having substantial experience in the handling and administration of radioactive material and, where applicable, the clinical management of radioactive patients.

Reference: State of Maine Rules Relating to Radiation Protection Sections G.66 to G.76.

Inspection

16. *Purpose, Frequency.* The possession and use of radioactive materials shall be subject to inspection by the regulatory authority and shall be subject to the performance of tests, as required by the regulatory authority. Inspection and testing is conducted to determine and to assist in obtaining compliance with regulatory requirements. Frequency of inspection shall be related directly to the amount and kind of material and type of operation licensed, and it shall be adequate to insure compliance.

Maine materials licensees will be subject to inspection by Radiation Control Program, Division of Health Engineering, the Department of Human Services. Upon instruction from the Department, licensees shall perform or permit the Department to perform any reasonable test and survey the Department consider appropriate or necessary. The frequency of inspections is dependent upon the types and scope of the licensed activities and will be at least as frequent as inspections of similar licensees by NRC. Generally, inspections will be unannounced.

References: State of Maine Rules Relating to Radiation Protection Sections A.5, A.6, A.7 and J.5.A; Maine Program Statement.

17. *Inspections Compulsory.* Licensees shall be under obligation by law to provide access to inspectors.

Maine regulations state that licensees shall afford the Department, at all reasonable times, opportunity to inspect sources of radiation and the premises and facilities wherein such sources of radiation are used or stored.

Reference: State of Maine Rules Relating to Radiation Protection Section A.5.

18. *Notification of Results of Inspection.* Licensees are entitled to be advised of the results of inspections and to notice as to whether or not they are in compliance.

Following Radiation Control Program inspections, each licensee will be notified in writing of the results of the inspection. The letters and written notices indicate if the licensee is in compliance and if not, list the areas of noncompliance.

Reference: Maine Program Statement.

Enforcement

19. *Enforcement.* Possession and use of radioactive materials should be amenable to enforcement through legal

sanctions, and the regulatory authority shall be equipped or assisted by law with the necessary powers for prompt enforcement. This may include, as appropriate, administrative remedies looking toward issuance of orders requiring affirmative action or suspension or revocation of the right to possess and use materials, and the impounding of materials; the obtaining of injunctive relief, and the imposing of civil or criminal penalties.

The Main Radiation Control Program is equipped with the necessary powers for prompt enforcement of the regulations. Where conditions exist that create a clear presence of a hazard to the public health that requires immediate action to protect human health and safety, Maine may issue orders to reduce, discontinue or eliminate such conditions. The Radiation Control Program actions may also include impounding of radioactive material, imposition of a civil penalty, revocation of a license, and requesting the State Attorney General to seek injunctions and convictions for criminal violations.

References: State of Maine Rules Relating to Radiation Protection Sections A.7, A.8, A.9, Part B and C.22; Maine Radiation Protection Act sections 688 and 690; Maine Program Statement.

Personnel

20. *Qualifications of Regulatory and Inspection Personnel.* The regulatory agency shall be staffed with sufficient trained personnel. Prior evaluation of applications for licenses or authorizations and inspection of licensees must be conducted by persons possessing the training and experience relevant to the type and level of radioactivity in the proposed use to be evaluated and inspected. This requires competency to evaluate various potential radiological hazards associated with the many uses of radioactive material and includes concentrations of radioactive materials in air and water, conditions of shielding, the making of radiation measurements, knowledge of radiation instruments—their selection, use, and calibration—laboratory design, contamination control, other general principles and practices of radiation protection, and use of management controls in assuring adherence to safety procedures. In order to evaluate some complex cases, the State regulatory staff may need to be supplemented by consultants or other State agencies with expertise in geology, hydrology, water quality, radiobiology, and engineering disciplines.

To perform the functions involved in evaluation and inspection, it is desirable that there be personnel educated and trained in the physical and/or life sciences, including biology, chemistry, physics and engineering, and that the personnel have had training and experience in radiation protection. For example, the person who will be responsible for the actual performance of evaluation and inspection of all of the various uses of byproduct, source and special nuclear material which might come to the regulatory body should have substantial training and extensive experience in the field of radiation protection. It is desirable that such a person have a bachelors degree or equivalent in the physical or life sciences, and specific training in radiation protection.

It is recognized that there will also be persons performing a more limited function in evaluation and inspection. These persons will perform the day-to-day work of the regulatory program and deal with both routine situations as well as some which will be out of the ordinary. These persons should have a bachelor's degree or equivalent in the physical or life sciences, training in health physics, and approximately two years of actual work experience in the field of radiation protection.

The foregoing are considered desirable qualifications for the staff who will be responsible for the actual performance of evaluation and inspection. In addition, there will probably be trainees associated with the regulatory program who will have an academic background in the physical or life sciences as well as varying amounts of specific training in radiation protection but little or no actual work experience in this field. The background and specific training of these persons will indicate to some extent their potential role in the regulatory program. These trainees, of course, could be used initially to evaluate and inspect those applications of radioactive materials which are considered routine or more standardized from the radiation safety standpoint, for example, inspection of industrial gauges, small research programs, and diagnostic medical programs. As they gain experience and competence in the field, trainees could be sued progressively to deal with the more complex or difficult types of radioactive material applications. It is desirable that such trainees have a bachelor's degree or equivalent in the physical or life sciences and specific training in radiation protection. In determining the requirement for academic training of individuals in all of the foregoing categories proper consideration should be given to equivalent competency which has been gained by appropriate technical and radiation protection experience.

It is recognized that radioactive materials and their uses are so varied that the evaluation and inspection functions will require skills and experience in the different disciplines which will not always reside in one person. The regulatory authority should have the composite of such skills either in its employ or as its command, not only for routine functions, but also for emergency cases.

(a) Number of Personnel

There are approximately 110 NRC specific licenses in the State of Maine. Under the proposed agreement, the State would assume responsibility for about 105 of these licenses. The Division of Health Engineering is currently staffed with 8 professional persons.

Donald Hoxie—Director, Division of Health Engineering. Responsible for the overall supervision of four State-wide regulatory programs, including the Radiological Health Program.

Wallace Hinckley—Assistant Director of Health Engineering. Responsible as Assistant Director for the overall supervision of four Statewide regulatory programs, including the Radiation Control Program.

Welllington Clough Toppan, Jr.—Manager, Radiation Control Program. Responsible for overall supervision of the Radiation Control Program, which regulates x-ray equipment and radionuclide users and conducts environmental monitoring of nuclear power facilities.

Robert Schell—Nuclear Engineering Specialist, Radiation Control Program. Responsible for environmental surveillance of and emergency planning for Maine Yankee Atomic Power Company.

David Breau—Sanitary Engineer II, Drinking Water Program. Responsible for review and approval of engineering plans for water treatment facilities. Backup staff available to the Radiation Control Program.

Linda A. Plausquellic—Radiation Specialist, Radiation Control Program. Performs compliance inspections and registration for x-ray machines. Assists in radioactive materials licensing program.

Jay Carl Hyland—Health Physicist, Radiological Health Program. Responsible for radioactive materials licensing and inspection program.

Cheryl Baker—Chemist II. Responsible for implementation of all radiological testing.

(b) Training

The academic and specialized short course training for those persons

involved in the administration, licensing and inspection of radiation control program is shown below:

Donald C. Hoxie—B.S. Chemical Engineering, University of Maine, M.S. Radiological Health, Rutgers University. U.S. Public Health Service, Basic Radiological Health. Two week course in 1960.

Oak Ridge Associated Universities, Health Physics Course. A 10-week course ending May 1961.
Brookhaven National Laboratory, Health Physics Training. A 4-week course ending September 1966.
Conference of Radiation Control Program Directors, Training for Radiation Therapy Inspections. November 3-25, 1984.
Conference of Radiation Control Program Directors, Training for Radon Control. November 28-29, 1986.

Wallace W. Hinckley—B.S., Civil Engineering, University of Maine.

University of Oklahoma, NIOSH Course. Safety and Health. January 8 to March 30, 1973.
Federal Emergency Management Agency. Radiological Emergency Response Planning. 1974 and 1978.
Federal Emergency Management Agency. Basic Radiological Defense Officers Course. Course I, March 7, 1975. Course II, March 14, 1975.
Harvard University, Basic Radiation Protection. April 4-8, 1977.
Harvard University, Environmental Surveillance. May 16-20, 1977.
Harvard University, Planning for Nuclear Emergencies. June 13-17, 1977.
U.S. Nuclear Regulatory Commission, Oak Ridge Associated Universities, Health Physics and Radiation Protection. A 5-week course ending April 14, 1978.
Federal Emergency Management Agency, Radiological Emergency Response Course. August 19-29, 1980.
Federal Emergency Management Agency, Radiological Accident Assessment Course. February 2-6, 1981.

Wellington Clough Toppan, Jr.—B.S., Civil Engineering, Norwich University, M.S., Environmental Engineering, Clarkson College of Technology, M.P.A., Public Administration, University of Maine at Orono.

Federal Emergency Management Agency, Radiological Emergency Response Planning. May 18-22, 1981.
Federal Emergency Management Agency, Basic Radiological Defense Officers. September 8-11, 1981.
Federal Emergency Management Agency, Radiological Accident Assessment. August 23-27, 1982.
New England Radiological Health Committee, Radiological Laboratory Workshop I. April 24-25, 1984.
Federal Emergency Management Agency, Radiological Emergency Response. September 12-21, 1984.
Conference of Radiation Control Program Directors, Training for Radiation Therapy Inspections. October 23-25, 1984.
U.S. Nuclear Regulatory Commission, Health Physics and Radiation Protection. February 3 to March 8, 1985.
New England Radiological Health Committee, Radiological Laboratory Workshop II. April 30 to May 2, 1985.
U.S. Nuclear Regulatory Commission, Introduction to Licensing Practices and Procedures. September 23-27, 1985.
Conference of Radiation Control Program Directors, Health Issues of Non Ionizing Radiation. October 29-30, 1985.
U.S. Environmental Protection, Indoor Radon Workshop. January 21-23-, 1986.
U.S. Nuclear Regulatory Commission, Medical Use of Radionuclides. March 15-20, 1987.
U.S. Nuclear Regulatory Commission, Pressurized Water Reactor Technology. April 28 to May 1, 1987.

U.S. Nuclear Regulatory Commission, Nuclear Transportation Course. August 17-21, 1987.

Southern Maine Vocational Technical School, Radon Mitigation Course. April 12-14, 1988.

Robert J. Schell—B.S., Bioengineering, University of Illinois.

United States Air Force Course, Bioenvironmental Engineering. March 18 to June 21, 1985.
Federal Emergency Management Agency, Radiological Emergency Response. October 16-26, 1985.
U.S. Nuclear Regulatory Commission, Introduction to Health Physics. February 10 to March 14, 1986.
Federal Emergency Management Agency, Radiological Response Planning. June 2-6, 1986.
Federal Emergency Management Agency, Radiological Accident Assessment. July 14-18, 1986.
University of Massachusetts Medical Center, Medical X-Ray Inspection, August 19-22, 1986.
U.S. Nuclear Regulatory Commission, Medical Uses of Radionuclides. September 8-12, 1986.
U.S. Nuclear Regulatory Commission, PRW Technology. February 23-27, 1987.
U.S. Nuclear Regulatory Commission, CE Technology. June 1-12, 1987.
U.S. Nuclear Regulatory Commission, Inspection Procedures. June 6-10, 1988.
U.S. Nuclear Regulatory Commission, Safety Aspects of Industrial Radiography. August 1-5, 1991.
Federal Emergency Management Agency, Advanced Radiological Accident Assessment. January 23-27, 1989.

David P. Breau—B.S., Civil Engineering, University of Maine at Orono.

Federal Emergency Management Agency, Basic Radiological Defense Officers Course. September 8-11, 1981.
Federal Emergency Management Agency, Nuclear Power Plant Offsite Accident Assessment Course. May 13-17, 1985.
U.S. Nuclear Regulatory Commission, Reactor Theory Operations and Emergency Planning. June 18-21, 1985.
Federal Emergency Management Agency, X-Ray Training. October 16-17, 1985.
Conference of Radiation Control Program Directors, Health Issues of Non Ionizing Radiation. October 29-30, 1985.
Federal Emergency Management Agency, Radiological Emergency Response Course. August 20–29, 1986.
U.S. Nuclear Regulatory Commission, Medical Use of Radionuclides. September 8–12, 1986.
U.S. Nuclear Regulatory Commission, Insepection Procedures Course. September 15–19, 1986.
U.S. Nuclear Regulatory Commission, Health Physics and Radiation Protection. July 20 to August 21, 1987.
U.S. Nuclear Regulatory Commission, Licensing and Practices and Procedures. September 21–25, 1987.

Linda A. Plusquellic—Maine Central Institute, The John Hopkins Hospital School of Radiologic Technology, University of Maine, working toward B.S., Public Administration.

New England Radiological Health Committee, Radon's Impact on State Radiation Control Programs. October 28–29, 1986.
U.S. Department of Health and Human Resources, Medical X-Ray Protection, March 23–27, 1987.
U.S. Department of Health and Human Resources, Basic Course for Investigators: Diagnostic X-Ray. April 27 to May 7, 1987.
Federal Emergency Management Agency, Radiological Emergency Response Course. September 9–18, 1987.
U.S. Nuclear Regulatory Commission, Inspection Procedures Course. September 25–29, 1989.

U.S. Nuclear Regulatory Commission, Medical Uses of Radionuclides. March 18–22, 1991.

Jay Carl Hyland—B.S., Engineering Physics, University of Maine, Orono.

Maine Emergency Management Agency, Fundamentals Course for Radiological Monitors. November 30 to December 1, 1988.
U.S. Nuclear Regulatory Commission, Medical Uses of Radionuclides. March 27–31, 1989.
Federal Emergency Management Agency, Radiological Accident Assessment. May 22–26, 1989.
U.S. Nuclear Regulatory Commission, Inspection Procedures Course. June 19–23, 1989.
U.S. Nuclear Regulatory Commission, Health Physics and Radiation Protection. July 10 to August 11, 1989.
U.S. Nuclear Regulatory Commission, Nuclear Transportation. August 14–18, 1989.
Federal Emergency Management Agency, Radiological Emergency Response Course. August 23 to September 1, 1989.
U.S. Nuclear Regulatory Commission, Special Topics Workshop. November 27 to December 1, 1989.
U.S. Nuclear Regulatory Commission, Licensing Practices and Procedures. June 11–15, 1990.
U.S. Nuclear Regulatory Commission, Special Topics Workshop. August 27–29, 1990.
U.S. Nuclear Regulatory Commission, Safety Aspects of Industrial Radiography. September 24–28, 1990.

Cheryl Baker—B.S., Chemistry University of Maine, Orono. U.S. Nuclear Regulatory Commission, Radiochemistry. February 9–13, 1981.

Public Health Laboratory, Radiation Safety in the Laboratory. July 28, 1983.
Federal Emergency Management Agency, Radiological Accident Assessment. March 5–9, 1984.
New England Radiological Health Committee, Radiological Laboratory Workshop. April 24–25, 1984.
Oak Ridge Associated Universities, Health Physics and Radiation Protection. July 9 to August 10, 1984.
New England Radiological Health Committee, Radiation Therapy Inspections. October 23–25, 1984.
New England Radiological Health Committee, Radiological Laboratory Workshop. April 30 to May 2, 1985.
New England Radiological Health Committee, Non Ionizing Radiation. October 29–30, 1985.
New England Radiological Health Committee, Radon's Impact on State Programs. October 28–29, 1986.
New England Radiological Health Committee, Radiological Laboratory Workshop. May 5–7, 1987.

Reference: Maine Program Statement.

21. *Conditions Applicable to Special Nuclear Material, Source Material and Tritium.* Nothing in the State's regulatory program shall interfere with the duties imposed on the holder of the materials by the NRC, for example, the duty to report to the NRC, on NRC prescribed forms (1) transfers of special nuclear material, source material and tritium and (2) periodic inventory data.

The State's regulations do not prohibit or interfere with the duties imposed by the NRC on holders of special nuclear material owned by the U.S. Department of Energy or licensed by NRC, such as the responsibility of licensees to supply to the NRC reports of transfer and inventory.

Reference: State of Maine Rules Relating to Radiation Protection Section A.1.

22. *Special Nuclear Material Defined.* Special nuclear material, in quantities not sufficient to form a critical mass, for present purposes means uranium enriched in the isotope U-235 in quantities not exceeding 350 grams of contained U-235; uranium 233 in quantities not exceeding 200 grams; plutonium in quantities not exceeding 200 grams; or any combination of them in accordance with the following formula: For each kind of special nuclear material, determine the ratio between the quantity of that special nuclear material and the quantity specified above for the same kind of special nuclear material. The sum of such ratios for all of the kinds of special nuclear material in combination should not exceed "1" (i.e., unity). For example, the following quanitities in combination would not exceed the limitation and are within the formula, as follows:

$$\frac{175 \text{ (grams contained U-235)}}{350} + \frac{50 \text{ (grams U-233)}}{200} + \frac{50 \text{ (grams Pu)}}{200} = 1$$

(This definition is subject to change by future Commission rule or regulation.)

The definition of special nuclear material in quantities not sufficient to form a critical mass, as contained in the Maine regulations, is uniform with the definition in 10 CFR part 150.

Reference: State of Maine Rules Relating to Radiation Protection Section A.2.A(62), Definition of Special Nuclear Material in Quantities Not Sufficient to Form a Critical Mass.

Administration

23. *Fair and Impartial Administration.* State practices for assuring the fair and impartial administration of regulatory law, including provision for public participation where appropriate, should be incorporated in procedures for:

(a) Formulation of rules of general applicability;

(b) Approving or denying applications for licenses or authorization to possess and use radioactive materials, and

(c) Taking discipl administrative and judicial review of actions taken by the Division of Health Engineering which includes the Maine Radiation Control Program.

Reference: Maine Administrative Procedure Act, State of Maine Rules Relating to Radiation Protection Sections A.9, A.11, C.22, and J.

24. *State Agency Designation.* The State should indicate which agency or agencies will have authority for carrying on the program and should provide the NRC with a summary of that legal authority. There should be assurances against duplicate regulation and licensing by State and local authorities, and it may be desirable that there be a single or central regulatory authority.

The Maine Department of Human Services in which the Maine Radiation Control Program is located has been designated as the State's radiation control agency.

References: Maine Radiation Protection Act, Section 674.1 and 686.

25. *Existing NRC Licenses and Pending Applications.* In affecting the discontinuance of jurisdiction, appropriate arrangements will be made by NRC and the State to ensure that there will be no interference with or interruption of licensed activities or the processing of license applications, by reason of the transfer. For Example, one approach might be that the State, in assuming jurisdiction, could recognize and continue in effect, for an appropriate period of time under State law, existing NRC licenses, including licenses for which timely applications for renewal have been filed, except where good cause warrants the earlier

reexamination or termination of the license.

Maine regulations have provisions for NRC licensees to possess a like license issued under the Maine regulations and the Maine Act. These licenses will expire either 90 days after receipt from the Agency of a notice of expiration of such license or on the date of expiration specified in the NRC license, whichever is earlier.

Reference: State of Maine Rules Relating to Radiation Protection Section C.19.

26. *Relations With Federal Government and Other States.* There should be an interchange of Federal and State information and assistance in connection with the issuance of regulations and licenses or authorizations, inspection of licensees, reporting of incidents and violations, and training and education problems.

The proposed agreement declares that the State will use its best efforts to cooperate with the NRC and the other Agreement States in the formulation of standards and regulatory programs for the protection against the hazards of radiation and to assure that the State's program will continue to be compatible with the Commission's program for the regulation of like materials.

Reference: Proposed Agreement between the State of Maine and the Nuclear Regulatory Commission, Article VI.

27. *Coverage, Amendments, Reciprocity.* The proposed Maine agreement provides for the assumption of regulatory authority over the following categories of materials within the State:

(a) Byproduct material, as defined by section 11.e(1) of the Atomic Energy Act, as amended.

(b) Source materials.

(c) Special nuclear materials in quantities not sufficient to form a critical mass.

Reference: Proposed Agreement, article I.

Provision has been made by Maine for the reciprocal recognition of licenses to permit activities within Maine of persons licensed by other jurisdictions. This reciprocity is like that granted under 10 CFR part 150.

Reference: State of Maine Rules Relating to Radiation Protection Section 3.X.

28. *NRC and Department of Energy Contractors.* The State's regulations provide that certain NRC and DOE contractors or subcontractors are exempt from the State's requirements for licensing and registration of sources of radiation which such persons receive, possess, use, transfer, or acquire.

Reference: State of Maine Rules Relating to Radiation Protection Section A.3.B.

III. Staff Conclusion

Section 274d of the Atomic Energy Act of 1954, as amended, states:

The Commission shall enter into an agreement under subsection b of this section with any State if:

(1) The Governor of the State certifies that the State has a program for the control of radiation hazards adequate to protect the public health and safety with respect to the materials within the State covered by the proposed agreement, and that the State desires to assume regulatory responsibility for such materials; and

(2) The Commission finds that the State program is in accordance with the requirements of subsection o. and in all other respects compatible with the Commission's program for the regulation of such materials, and that the State program is adequate to protect the public health and safety with respect to the materials covered by the proposed amendment.

The staff has concluded that the State of Maine meets the requirements of section 274 of the Act. The State's statutes, regulations, personnel, licensing, inspection and administrative procedures are compatible with those of the Commission adequate to protect the public health and safety with respect to the materials covered by the proposed agreement. Since the State is not seeking authority over uranium milling activities, subsection o. is not applicable to the proposed Maine agreement.

Dated at Rockville, Maryland, this 22nd Day of November 1991.

For the U.S. Nuclear Regulatory Commission.

Carlton Kammerer,

Office of State Programs.

Appendix A

Agreement Between the United States Nuclear Regulatory Commission and the State of Maine for Discontinuance of Certain Commission Regulatory Authority and Responsibility Within the State Pursuant to Section 274 of the Atomic Energy Act of 1954, as Amended

Whereas, The United States Nuclear Regulatory Commission (hereinafter referred to as the Commission) is authorized under section 274 of the Atomic Energy Act of 1954, as amended (hereinafter referred to as the Act), to enter into agreements with the Governor of any State providing for discontinuance of the regulatory authority of the Commission within the State under chapters 6, 7, and 8, and section 161 of the Act with respect to byproduct materials as defined in sections 11e. (1) and (2) of the Act, source materials, and special nuclear materials in quantities not sufficient to form a critical mass; and,

Whereas, The Governor of the State of Maine is authorized under Maine Revised Statutes Annotated section 284 to enter into this Agreement with the Commission; and,

Whereas, The Governor of the State of Maine certified on March 5, 1990, that the State of Maine (hereinafter referred to as the State) has a program for the control of radiation hazards adequate to protect the public health and safety with respect to the materials within the State covered by this Agreement, and that the State desires to assume regulatory responsibility for such materials; and

Whereas, The State and the Commission recognize the desirability and importance of cooperation between the Commission and the State in the formulation of standards for protection against hazards of radiation and in assuring that State and Commission programs for protection against hazards of radiation will be coordinated and compatible; and,

Whereas, The Commission and the State recognize the desirability of reciprocal recognition of licenses and exemptions from licensing of those materials subject to this Agreement; and

Whereas, This Agreement is entered into pursuant to the provisions of the Act, as amended;

Now Therefore, it is hereby agreed between the Commission and the Governor of the State, acting in behalf of the State, as follows:

Article I

Subject to the exceptions provided in articles II, IV, and V, the Commission shall discontinue, as of the effective date of this Agreement, the regulatory authority of the Commission in the State under chapters 6, 7, and 8, and section 161 of the Act with respect to the following materials:

A. Byproduct materials as defined in section 11e.(1) of the Act;

B. Source materials; and

C. Special nuclear materials in quantities not sufficient to form a critical mass.

Article II

This Agreement does not provide for discontinuance of any authority and the Commission shall retain authority and responsibility with respect to regulation of;

A. The construction and operation of any production or utilization facility;

B. The export from or import into the United States of byproduct, source, or special nuclear material, or of any production or utilization facility;

C. The disposal into the ocean or sea of byproduct, source, or special nuclear waste materials as defined in regulations or orders of the Commission;

D. The disposal of such other byproduct source, or special nuclear material as the Commission from time to time determines by regulation or order should, because of the hazards or potential hazards thereof, not be so disposed of without a license from the Commission;

E. The land disposal of source, byproduct and special nuclear material received from other persons; and,

F. The extraction or concentration of source material from source material ore and the management and disposal of the resulting byproduct material.

Article III

This Agreement may be amended, upon application by the State and approval by the Commission, to include the additional area(s) specified in article II, paragraph E or F, whereby the State can exert regulatory control over the materials stated herein.

Article IV

Notwithstanding this Agreement, the Commission may from time to time by rule, regulation, or order, require that the manufacturer, processor, or producer of any equipment, device, commodity, or other product containing source, byproduct, or special nuclear material shall not transfer possession or control of such product except pursuant to a license or an exemption from licensing issued by the Commission.

Article V

This Agreement shall not affect the authority of the Commission under subsection 161 b. or i. of the Act to issue rules, regulations, or orders to protect the common defense and security, to protect restricted data or to guard against the loss or diversion of special nuclear material.

Article VI

The Commission will use its best efforts to cooperate with the State and other Agreement States in the formulation of standards and regulatory programs of the State and the Commission for protection against hazards of radiation and to assure that State and Commission programs for protection against hazards of radiation will be coordinated and compatible. The State will use its best efforts to cooperate with the Commission and other Agreement States in the formulation of standards and regulatory programs of the State and the Commission for protection against hazards of radiation and to assure that the State's program will continue to be compatible with the program of the Commission for the regulation of like materials. The State and the Commission will use their best efforts to keep each other informed of proposed changes in their respective rules and regulations and licensing, inspection and enforcement policies and critiera, and to obtain the comments and assistance of the other party thereon.

Article VII

The Commission and the State agree that it is desirable to provide reciprocal recognition of licenses for the materials listed in Article I licensed by the other party or by any Agreement State. Accordingly, the Commission and the State agree to use their best efforts to develop appropriate rules, regulations, and procedures by which such reciprocity will be accorded.

Article VIII

The Commission, upon its own initiative after reasonable notice and opportunity for hearing to the State, or upon request of the Governor of the State, may terminate or suspend all or part of this Agreement and reassert the licensing and regulatory authority vested in it under the Act if the Commission finds that (1) such termination or suspension is required to protect the public health and safety, or (2) the State has not complied with one or more of the requirements of section 274 of the Act. The Commission may also, pursuant to section 274j of the Act, temporarily suspend all or part of this Agreement if, in the judgement of the Commission, an emergency situation exists requiring immediate action to protect public health and safety and the State has failed to take necessary steps. The Commission shall periodically review this Agreement and actions taken by the State under this Agreement to ensure compliance with section 274 of the Act.

Article XI

This agreement shall become effective on ———, and shall remain in effect unless and until such time as it is terminated pursuant to article VIII.

For the U.S. Nuclear Regulatory Commission.

Ivan Selin,

Chairman,

For the State of Maine.

John R. McKernan, Jr.,

Governor.

[FR Doc. 91-28908 Filed 12-2-91; 8:45 am]

BILLING CODE 7590-01-M

NUCLEAR WASTE TECHNICAL REVIEW BOARD

Full Board Meeting

Pursuant to its authority under section 5051 of Public Law 100-203, the Nuclear Waste Policy Amendments Act of 1987, the Nuclear Waste Technical Review Board (the Board) will hold a full Board meeting in Arlington, Virginia, on January 7 and 8, 1992. The purpose of this meeting will be to provide Board members with an understanding of the current and future research priorities and funding allocations for the Department of Energy's (DOE) Office of Civilian Radioactive Waste Management (OCRWM), especially as they relate to the DOE's site-characterization program at Yucca Mountain, Nevada. Dr. John Bartlett, director of OCRWM, and appropriate associate directors and staff, have been invited to participate in the meeting. Sessions will run from 9 a.m. to 5:30 p.m. on January 7 and from 8:30 a.m. to 12 noon on January 8, 1992. The meeting will be held at the Key Bridge Marriott, Potomac Ballroom, 1401 Lee Highway, Arlington, Virginia 22209; 703-524-6400, and will be open to the public.

Recent budget decisions have affected the DOE's priorities for its Yucca Mountain site-characterization program. Therefore, the board has asked the DOE for a detailed review of the funding allocations and rationale for the OCRWM's Yucca Mountain Site Characterization Program. The Board also would like the DOE's best estimates of the funding and time required to complete a full site-characterization program. Of special interest to the Board is how funding reductions for fiscal year 1992 have affected current program activities and how future funding decisions could affect the program. The Board also has asked the DOE to review any contingency plans that may have been developed for dealing with potential future budgetary shortfalls.

In addition to a discussion of the budget and related issues, the Board would like the DOE to provide a report on systems integration, including an update on the M&O contract for OCRWM and for the Yucca Mountain Site Characterization Project Office.

Transcripts of the meeting will be available on a library-loan basis from Victoria Reich, Board librarian, beginning February 24, 1992. For more information, contact Paula N. Alford, Director, External Affairs, Nuclear Waste Technical Review Board, 1100 Wilson Boulevard, suite 910, Arlington, Virginia 22209; 703-235-4473.

Dated: December 29, 1991.

William D. Barnard,

Executive Director, Nuclear Waste Technical Review Board.

[FR Doc. 91-28975 Filed 12-2-91; 8:45 am]

BILLING CODE 6820-AM-M

OFFICE OF MANAGEMENT AND BUDGET

Office of Federal Procurement Policy

Cost Accounting Standards Board; Notice of Open Session of Board Meeting

AGENCY: Cost Accounting Standards Board, Office of Federal Procurement Policy, OMB.

ACTION: Notice.

SUMMARY: The Office of Federal Procurement Policy, Cost Accounting Standards Board (CASB), is hereby providing notice of its intention to hold an open public session during a Board meeting on Thursday, January 16, 1992, from 1 to 5 p.m. This session of the meeting will be held in room 450 of the Old Executive Office Building, 17th Street and Pennsylvania Ave., NW, Washington, DC. During this open

session, the Board will hear the views of interested parties concerning various topics on the Board's current agenda of issues meriting regulatory consideration.

DATES: Due to time and seating consideration, individuals desiring to attend the open session of the Board's meeting, or to make a presentation before the Board, must notify the CASB staff, in writing, no later than December 17, 1991.

ADDRESSES: Requests to attend the open session of the Board's meeting must be in writing, and should be addressed to Ms. Barbara Diering, Special Assistant, Cost Accounting Standards Board, Office of Federal Procurement Policy, 725 17th Street, NW, room 9001, Washington, DC 20503. Attn: CASB Docket No. 91-08.

FOR FURTHER INFORMATION CONTACT: Barbara Diering, Special Assistant, Cost Accounting Standards Board (telephone 202-395-3254).

SUPPLEMENTARY INFORMATION: The Office of Federal Procurement Policy, Cost Accounting Standards Board, will hold its next meeting on January 16 and 17, 1992. During this meeting, there will be an open public session on Thursday, January 16, 1992, from 1 until 5 p.m. The purpose of this public session will be to hear the views of interested persons concerning various topics the Board is considering relating to the rules governing measurement, assignment and allocation of costs to contracts with the United States Government.

Individuals desiring to attend this open session must notify the Board's staff, in writing, at the above listed address, by the deadline noted. If an individual desires to make a presentation to the Board at this session, he or she is required to submit a brief outline of the presentation when making the request. In addition, a full written statement must be submitted two weeks prior to the Board's meeting. In lieu of making an oral presentation, individuals may submit a written statement for the record.

To obtain entrance to the Old Executive Office Building, all potential attendees must include in their request: (1) Their full name, (2) organizational affiliation (if any), and, (3) date of birth. Also, due to time and potential space limitations in the Board's meeting room, the Board will notify individuals of their attendance and/or speaking status prior to the meeting. Time allocations for oral presentations will depend on the number of individuals who desire to appear before the Board.

AGENDA: The Board, in particular, solicits presentations for its public meeting on the following topics, all of which are a part of the Board's current regulatory agenda:

1. Recodification of Cost Accounting Standards Board rules and regulations.
2. Pay-as-you-go (unfunded) pension costs.
3. Pension costs—full funding limitation.
4. Thresholds for cost accounting standards coverage.
5. Asset revaluations resulting from mergers and business combinations.
6. Establishment of cost accounting standards for colleges and universities.
7. Cost accounting standards coverage for non-defense contracts.

Also, given time considerations, the Board would be pleased to hear comments on the conceptual framework project (statement of objectives, policies and concepts), and other matters that may be of interest to affected parties.

Allan V. Burman,

Administrator for Federal Procurement Policy and Chairman, Cost Accounting Standards Board.

[FR Doc. 91-28862 Filed 12-2-91; 8:45 am]

BILLING CODE 3110-01-M

OFFICE OF THE UNITED STATES TRADE REPRESENTATIVE

[Docket No. 301-86]

Determination To Extend the Investigation of the Intellectual Property Laws and Practices of the Government of the People's Republic of China

AGENCY: Office of the United States Trade Representative.

ACTION: Notice of determination under section 304(a)(3)(B) of the Trade Act of 1974, as amended (Trade Act), 19 U.S.C. 2414(a)(3)(B), to extend the investigation of the acts, policies and practices of the Government of the People's Republic of China on the protection and enforcement of intellectual property rights.

SUMMARY: Pursuant to section 304(a)(3)(B) of the Trade Act, the United States Trade Representative (USTR) has determined to extend the investigation initiated under section 302(b)(2)(A) of the Trade Act of certain acts, policies and practices of the People's Republic of China that deny adequate and effective protection of intellectual property rights.

DATES: The USTR made this determination on November 26, 1991.

FOR FURTHER INFORMATION CONTACT: Lee Sands, Director, China and Mongolian Affairs (202) 395-5050, Emery Simon, Deputy Assistant USTR for Intellectual Property (202) 395-6864, or Catherine Field, Associate General Counsel (202) 395-3432, Office of the United States Trade Representative.

SUPPLEMENTARY INFORMATION: On may 26, 1991, the USTR initiated an investigation of deficiencies in the acts, policies and practices of the People's Republic of China (China) related to the denial of adequate and effective protection of intellectual property rights in China. These deficiencies include: (1) Deficiencies in its patent law, in particular, the failure to provide product patent protection for chemicals, including pharmaceuticals and agrichemicals (2) lack of copyright protection for U.S. works not first published in China, (3) deficient levels of protection under the copyright law and regulations, (4) inadequate protection of trade secrets, and (5) the absence of effective enforcement of intellectual property rights in China, including rights in trademarks.

A series of detailed bilateral negotiations have been held on these issues since the initiation of this investigation. The two governments, however, have not yet been able to resolve all of the complex and complicated issues involved.

In light of the need for further time for negotiations to resolve these issues, the USTR has determined pursuant to section 304(a)(3)(B)(i) of the Trade Act, that "complex or complicated issues are involved in the investigation that require additional time." Thus, USTR's determinations under section 304(a)(1) on actionability and what action, if any, should be taken in response must be made no later than February 26, 1992.

Joshua B. Bolten,

General Counsel.

[FR Doc. 91-28911 Filed 12-2-91; 8:45 am]

BILLING CODE 3190-01-M

[Docket No. 301-85]

Determination To Extend the Investigation of the Intellectual Property and Market Access Acts, Policies and Practices of the Government of India

AGENCY: Office of the United States Trade Representative.

ACTION: Notice of determination under section 304(a)(3)(B) of the Trade Act of 1974, as amended (Trade Act), 19 U.S.C. 2414(a)(3)(B), to extend the investigation of the intellectual property and market access acts, policies and practices of the Government of India.

SUMMARY: Pursuant to section 304(a)(3)(B) of the Trade Act, the United States Trade Representative (USTR) has determined to extend the investigation initiated under section 302(b)(2)(A) of the Trade Act of certain acts, policies and practices of the government of India that deny adequate and effective protection of intellectual property rights and fair and equitable market access to United States persons that rely upon intellectual property protection.

DATES: The USTR made this determination on November 26, 1991.

FOR FURTHER INFORMATION CONTACT: Peter Collins, Director, Southeast Asian and Indian Affairs (202) 395–6813, Emery Simon, Deputy Assistant U.S. Trade Representative for Intellectual Property (202) 395–6864, or Catherine Field, Associate General Counsel (202) 395–3432, Office of the United States Trade Representative.

SUPPLEMENTARY INFORMATION: On May 26, 1991, the USTR initiated an investigation of deficiencies in the acts, policies and practices of the Government of India with respect to protection of intellectual property and market access for U.S. persons relying on intellectual property. With respect to intellectual property the issues under investigation include:

(1) Numerous deficiencies in its patent law, in particular the failure to provide product patent protection for a wide range of products including pharmaceuticals and products resulting from chemical processes, an inadequate term of protection, and overly broad involuntary licensing provisions;

(2) Lack of protection for service marks and restrictions on use of foreign trademarks;

(3) Copyright compulsory licensing provisions that are overly broad, and

(4) The absence of effective enforcement of intellectual property rights in India including copyrights which has led to a high level of piracy in that country.

With respect to market access for persons that rely on intellectual property protection, India restrained access through quotas, fees and other barriers.

A series of bilateral consultations have been held on these issues since the initiation of this investigation as well as continued work on intellectual property matters in the Uruguay Round negotiations on trade aspects of intellectual property. The two governments, however, have not yet been able to resolve all of the complex and complicated issues involved.

In light of the need for further time for negotiations to resolve the issues under investigation, the USTR has determined pursuant to section 304(a)(3)(B)(i) of the Trade Act, that "complex or complicated issues are involved in the investigation that require additional time." Thus, USTR's determinations under section 304(a)(1) on actionability and what action, if any, should be taken in response must be made no later than February 26, 1992.

Joshua B. Bolten,

General Counsel.

[FR Doc. 91–28912 Filed 12–2–91; 8:45 am]

BILLING CODE 3190-01-M

POSTAL SERVICE

Proposed Changes in International Priority Airmail (IPA) Rates

AGENCY: Postal Service.

ACTION: Proposed changes in International Priority Airmail (IPA) rates.

SUMMARY: Pursuant to its authority under 39 U.S.C. 407, the Postal Service is proposing to replace the current worldwide presorted IPA rate option with a new zoned rate option that would have three rate groups consisting of destination countries employing common terminal dues systems. It is proposed that these changes would become effective on or about March 1, 1992.

DATES: Comments on the proposed changes must be received on or before January 2, 1991.

ADDRESSES: Director, Office of Rates, Rates and Classification Department, U.S. Postal Service, Washington, DC 20260–5350. Copies of all written comments will be available for public inspection and photocopying between 9 a.m. and 4 p.m., Monday through Friday, in room 1140, 475 L'Enfant Plaza West, SW., Washington, DC.

FOR FURTHER INFORMATION CONTACT: John F. Alepa (202) 268–2650.

SUPPLEMENTARY INFORMATION: International Priority Airmail (IPA) service is faster than regular international airmail service and is available to bulk mailers of LC and AO items, through designated gateway areas, to all foreign countries except Canada. To qualify, a mailing must consist of either 200 pieces or 10 pounds. This minimum applies to the entire mailing and not to each destination country.

The Postal Service currently offers two IPA service options, worldwide presorted and worldwide nonpresorted. The presorted option, which was introduced in 1986, requires the mailer to presort items to destination country. In contrast, the nonpresorted option, which was introduced in June 1990, does not require the mailer to perform that worksharing activity. At present, the presorted rate is $7.00 per pound or fraction of a pound and the nonpresorted rate is $8.50 per pound or fraction of a pound.

Both current rates are worldwide rates that apply to all IPA mail regardless of destination. This approach made sense when IPA service began, as the most significant components of the Postal Service's costs, namely transportation expenses and terminal dues, were based exclusively on weight. Although transportation expenses are still a function of weight, terminal dues payments, for the most part, now reflect both weight and piece volume. Consequently, the Postal Service incurs substantially different costs for delivering IPA pieces to different countries.

Since the introduction of IPA service, the countries to which the bulk of U.S. mail is sent have implemented terminal dues arrangements that recognize that mail processing costs vary by volume as well as by weight. The terminal dues system dopted by the 20th Congress of the Universal Postal Union (UPU) takes into account the number of pieces per pound in setting compensation levels. Further, the terminal dues system used by a number of European countries in lieu of the UPU method is predicated on an explicit per-piece plus per-pound rate.

These structural changes in the way terminal dues compensation is calculated have made light-weight items proportionally more costly to the Postal Service than heavier items, yet the existing flat pound-based rate structure offers no mechanism to gain commensurate revenue. Mailers, in general, and mailers of light-weight items, in particular, have recognized that increasing the number of pieces per unit of weight lowers the unit cost per piece when a per-pound rate applies. The pound-rate structure has allowed lightweight mailers to increase the number of pieces per unit of weight mailed without facing additional postage costs. The adverse cost consequences of high-density mailings have been exacerbated by the migration of light-weight printed matter from International Service Air Life (ISAL) to IPA following ISAL rate restructuring implemented on January 12, 1991.

In light of the foregoing, the Postal Service proposes to revise the current IPA rate structure. The purpose of this proposal is threefold. First, the changes would result in a rate mechanism that

provided reasonable revenue generation with respect to cost without unduly burdening any category of mailers by virtue of their mail's make-up or weight characteristics. Second, the proposal would recognize the advantage to mailers of rates that not only reflected underlying costs, but also provided mailers with the ability to determine for themselves which offering best accommodated their needs. Finally, the changes would broaden the utility of IPA service by providing flexibility in how the rates would be applied and under what conditions mailers could use them. The structural changes proposed would replace the current worldwide presorted rate option with a new zoned rate option. In addition, all IPA rates would consist of both per-piece and per-pound rate elements. The proposed rates are summarized in Table 1 below.

The worldwide rate option, under this proposal, would be essentially equivalent to the current worldwide nonpresorted rate option in terms of its applicability to all IPA destination countries and its lack of a presort requirement. There would no longer be a worldwide presorted rate option. The worldwide option would continue to require a minimum of ten pounds or 200 pieces to qualify for the service, and the preparation requirements would not change. To address the effects of high-density mailings discussed above, the Postal Service would replace the current flat pound-based worldwide rate with a rate that took into account both the weight and piece volume of a mailing. The rate proposed for the worldwide option would be 20 cents per piece plus $8.00 per pound. Postage would be calculated by multiplying the number of pieces in the mailing by the per-piece rate, multiplying the weight of the mailing by the per-pound rate, and then adding the two totals together.

The Postal Service is also proposing to establish a new zoned rate option with three different rate groups. The rate groups would consist of destination countries employing common terminal dues systems and, thus, would reflect differences in the costs incurred by the Postal Service. The zoned rates would also reflect differences in costs other than terminal dues. The proposed rate groups are listed in Table 2.

The zoned option would require a minimum of ten pounds or 200 pieces to a single zone to qualify the service. This minimum would apply to each zone rather than to the entire mailing. Whatever portion of an IPA mailing did not meet the minimum would have to be sent at the worldwide rate. Mailers using the zoned option would be required to presort items to destination country and to make up their mail in accordance with current sections 284.4 through 284.5 of the International Mail Manual. The residual portion of a zoned IPA mailing that could not be made up into a country bundle would also have to be sent at the worldwide rate.

The three zoned rates would consist of both per-piece and per-pound rate elements. The rates proposed for the zoned option would range from 20 cents per piece and $4.95 per pound to 15 cents per piece and $7.95 per pound. Postage for each rate group would be calculated by multiplying the number of pieces in the mailing destined for countries in that rate group by the appropriate per-piece rate, multiplying the weight of those pieces by the corresponding per-pound rate, and then adding the two totals together.

With the implementation of the new IPA rate structure containing worldwide and zoned options, the postage payment methods would change. For nonidentical weight pieces, each piece would require a postage meter impression for the per-piece rate. For identical weight pieces, each piece could bear either a permit imprint or postage meter impression for the per-piece rate. Postage for the pound rate portion could be paid from an advance deposit account, by meter strip attached to the mailing statement, or through the international billing program. Mailers could use permit imprints for nonidentical pieces only when the mailer was authorized by the Postal Service to use one of the postage payment systems described in Domestic Mail Manual 145.7, 145.8, or 145.9.

As required by the Postal Reorganization Act, the proposed changes would result in IPA rates that (1) would not apportion the costs of the service so as to impair the overall value of the service to the users; (2) would apportion the costs of all postal operations to all users on a fair and equitable basis; (3) would be fair and reasonable; and (4) would not be unduly or unreasonably discriminatory or preferential. Although 39 U.S.C. 407 does not require advance notice and opportunity for submission of comments, and the Postal Service is exempted by 39 U.S.C. 410(a) from the advance notice requirements of the Administrative Procedure Act regarding proposed rulemaking (5 U.S.C. 553), the Postal Service invites interested persons to submit written data, views, or arguments concerning the proposed changes.

Authority: 39 U.S.C. 407, 410.

Stanley F. Mires,

Assistant General Counsel, Legislative Division.

TABLE 1.—INTERNATIONAL PRIORITY AIRMAIL PROPOSED RATES

World-wide rate	Zoned rates [1] (Presort Only)		
Non-Presort	Rate Group 1	Rate Group 2	Rate Group 3
20 cents per piece plus $8.00 per lb	20 cents per piece plus $4.95 per lb	15 cents per piece plus $6.15 per lb	15 cents per piece plus $7.95 per lb.

[1] Requires a minimum of ten (10) pounds or two hundred (200) pieces per zone.

TABLE 2.—IPA RATE GROUPS

Rate group 1	Rate group 2	Rate group 3
Australia, Corsica, Denmark, Faroe Island, Finland, France (includes New Caldedonia and Wallis & Futuna), Germany, Great Britain & Northern Ireland, Greenland, Iceland, Ireland, Italy, Japan, Luxembourg, Netherlands, Norway, Sweden.	Afghanistan, Albania, Algeria, Andorra, Angola, Anguilla, Antigua & Barbuda, Argentina, Aruba, Ascension, Bahamas, Bahrain, Bangladesh, Barbados, Belize, Benin, Bermuda, Bhutan, Bolivia, Botswana, Brazil, British Virgin Islands, Brueni, Bulgaria, Burkina Faso, Burundi, Cameroon, Cape Verdi, Cayman Island, Central African Republic, Chad, Chile, Comoros, Congo, Costa Rica, Cote D'Ivoire, Cuba, Cyprus, Djibouti, Dominica, Dominican Republic, East Timor, Ecuador, Egypt, El Salvador, Equatorial Guinea, Ethiopia, Falkland Island, Fiji Island, French Guiana, French Polynesia, Gabon, Gambia, Ghana, Gibraltar, Grenada, Guadeloupe, Guatemala, Guinea, Guinea-Bissau, Guyana, Haiti, Honduras, Indonesia, Iraq, Jamaica, Jordan, Kampuchea, Kenya, Kiribati, Korea, (Democratic Peoples Republic of), Kuwait, Lao, Lebanon, Lesotho, Liberia, Libya, Liechtenstein, Macao, Madagascar, Malawi, Maldives, Mali, Malta, Martinique, Mauritania, Mauritius, Monaco, Mongolia, Montserrat, Morocco, Mozambique, Myanmar (Burma), Naura, Nepal, Netherland Antilles, New Caldonia, Nicaragua, Niger, Nigeria, Oman, Pakistan, Panama, Papua New Guinea, Paraguay, Peru, Pitcairn Island, Qatar, Reunion, Romania, Rwanda, Saint Christopher & Nevis, Saint Helena, Saint Lucia, Saint Pierre & Miquelon, Saint Vincent & The Grenadines, San Marino, Sao Tome & Principe, Senegal, Seychelles, Sierra Leone, Solomon Island, Somolia, Sri Lanka, Sudan, Suriname, Swaziland, Syria, Tanzania, Togo, Tonga, Trinidad/Tobago, Tristan Da Cunha, Tunisia, Turkey, Turks and Caicos Island, Tuvalu, Uganda, United Arab Emirates, Uruguay, Vanuatu, Vatican City, Venezuela, Vietnam, Western Samoa, Yemen, Zaire, Zambia, Zimbabwe.	Austria, Azores, Belgium, China, Colombia, Czechoslovakia, Estonia, Greece, Hong Kong, Hungary, India, Iran, Israel, Korea, Republic of (South), Latvia, Lithuania, Madeira Island, Malaysia, Mexico, New Zealand, Philippines, Poland, Portugal, Saudi Arabia, Singapore, South Africa, Spain, Switzerland, Taiwan, Thailand, USSR, Yugoslavia

[FR Doc. 91-28910 Filed 12-2-91; 8:45 am]

BILLING CODE 7710-12-M

Proposed Changes in International Surface Air Lift (ISAL) Rates

AGENCY: Postal Service.

ACTION: Proposed changes in International Surface Air Lift (ISAL) rates.

SUMMARY: Pursuant to its authority under 39 U.S.C. 407, the Postal Service is proposing to increase rates for ISAL mail. It is proposed that these changes become effective on or about March 1, 1992.

DATES: Comments must be received on or before January 2, 1991.

ADDRESSES: Director, Offices of Rates, Rates and Classification Department, U.S. Postal Service, Washington, DC 20260-5350. Copies of all written comments will be available for public inspection and photocopying between 9 a.m. and 4 p.m., Monday through Friday, in room 1140, 475 L'Enfant Plaza West, SW., Washington, DC.

FOR FURTHER INFORMATION CONTACT: John F. Alepa (202) 268-2650.

SUPPLEMENTARY INFORMATION: International Surface Air Lift (ISAL) is a bulk mailing service for international shipment of publications, advertising mail, catalogs, directories, books, and other printed matter. The service is available from designated acceptance cities to approximately 125 countries. To use ISAL, a mailer must send at least 50 pounds of printed matter at one time, presorted by country of destination. Identical piece mailings are not required to qualify. Postage for ISAL mailings is calculated according to a break-point system, with the rate structure including both per-piece and per-pound elements. For ISAL items weighing over two ounces, full service postage currently ranges from $2.85 to $4.20 per pound, depending on country of destination; gateway/direct ship postage currently ranges from $2.55 to $3.90 per pound, depending on country of destination. For ISAL items weighting two ounces or less, full service postage currently is 24 cents per piece regardless of country of destination. A 30-cents-per-pound discount is currently given to ISAL mail tendered at the gateway airport mail facilities at New York (JFK), San Francisco, CA, and Miami, FL, or when direct shipment (750 pounds or more to a single destination) can be arranged from one of the acceptance cities. An additional 20% discount is currently available for M Bags (mail to a single addressee sacked in specially-labeled bags and subject to a minimum sack weight requirement.) [1]

The Postal Service adopted the current ISAL rate structure, effective January 12, 1991, on November 2, 1990 (55 FR 46268), in order to reflect more accurately the way ISAL costs are incurred. Prior to that rate change, postage for ISAL mailings was calculated solely by weight, without regard to the number of pieces contained within a mailing. The pound-rate structure allowed lightweight mailers to increase the number of pieces per unit of weight mailed without facing additional postage costs; the additional cost, namely terminal dues expense, was borne solely by the Postal Service. That practice accelerated the growth in ISAL costs per piece relative to costs per pound and, in part, necessitated the establishment of the per-piece rate element. Also contributing to the need for the per-piece rate element was the change by many foreign postal administrations from strictly pound-related terminal dues structures to terminal dues structures based on an implicit average number of items per

[1] ISAL M Bags can be sent to all ISAL destination countries except Ethiopia.

unit weight or on an explicit piece/pound charge.

The current rate structure tracks ISAL costs much better than the per-pound structure did. The break-point system recognizes, for example, that delivering one pound of ISAL mail consisting of 40 pieces costs the Postal Service considerably more than does delivering one pound of ISAL mail consisting of only four items. Based on its own analysis of costs and traffic patterns, and after consideration of comments received in response to a piece-plus-pound proposal published on July 6, 1990 (55FR 27915), the Postal Service established the break point at two ounces, above which only the per-pound rate applies and at or below which only the per-piece rate applies.

The break-point rate structure replace ISAL rates that had been in effect since July 1987. The Postal Service adopted the break-point system in lieu of its original piece-plus-pound proposal to moderate the impact of the resulting rate increase on mailers of lightweight items. This was accomplished both by adopting a relatively low initial per-piece rate and by increasing the availability of discounts from full service ISAL rates for mailers that engage in worksharing. The Postal Service believes that the mailing community has adapted to the current ISAL rate structure, and consequently proposes to adjust rate levels. Specifically, it is proposed that the full service per-piece rate would increase from 24 cents to 32 cents. In addition, rate adjustments, varying up to 3 percent, are proposed for per-pound rates, including full service, M-Bag, gateway discount, and direct ship discount rates. The differential between full service rates and gateway/direct ship rates would remain at 30 cents per pound, still reflecting the cost savings in domestic transportation. The proposed ISAL rates are shown in the table below.

As required by the Postal Reorganization Act, the proposed changes would result in ISAL rates that (1) would not apportion the costs of the service so as to impair the overall value of the service to the users; (2) would apportion the costs of all postal operations to all users on a fair and equitable basis; (3) would be fair and reasonable; and (4) would not be unduly or unreasonably discriminatory or preferential.

Although 39 U.S.C. 407 does not require advance notice and opportunity for submission of comments, and the Postal Service is exempted by 39 U.S.C. 410(a) from the advance notice requirements of the Administrative Procedure Act regarding proposed rulemaking (5 U.S.C. 553), the Postal Service invites interested persons to submit written data, views, or arguments concerning the proposed changes.

As a separate issue for further consideration, the Postal Service is also seeking comments from mailers regarding the establishment of a minimum sack weight for ISAL mailings. While a mailing must meet a minimum weight requirement of 50 pounds to qualify for ISAL, there is currently no minimum weight requirement for individual sacks within a mailing, except for M Bags. The Postal Service is not seeking to exclude any portion of a qualifying mailing from utilizing ISAL. Rather, portions of an ISAL mailing that were separately sacked and whose sack weights were less than the prescribed minimum would be accepted for ISAL service, but would either be rated at a higher residual rate or have a surcharge applied to each sack failing to meet the minimum.

The Postal Service believes that the establishment of a practical and reasonable minimum sack weight requirement together with the rating of residual volume would contribute to maintaining efficiency of operation and adequate cost recovery.

The Postal Service solicits the view of interested parties on this topic. Consideration of comments received on this topic will be used to offer specific proposals independent of the ISAL rate revisions proposed today.

Authority: 39 U.S.C. 407, 410.

Stanley F. Mires,

Assistant General Counsel, Legislative Division.

PROPOSED ISAL RATES

Rate per piece 2 ounces or less		Rate per pound pieces weighing over 2 ounces			
Rate group	All services except M-Bag	Full service		Gateway/direct ship	
		Regular	M-Bag	Regular	M-Bag
1	$0.32	$2.90	$2.32	$2.60	$2.08
2	0.32	3.25	2.60	2.95	2.36
3	0.32	3.40	2.72	3.10	2.48
4	0.32	4.20	3.36	3.90	3.12

ISAL RATE GROUPS

Group 1, Europe	Group 2, Western Hemisphere	Group 3, Pacific Rim	Group 4, Africa/Asia
Albania, Austria, Belgium, Bulgaria, Czechoslovakia, Denmark, Finland, France, Germany, Great Britain & Northern Ireland, Greece, Hungary, Iceland, Ireland, Italy, Liechtenstein, Luxembourg, Netherlands, Norway, Poland, Portugal, Romania, San Marino, Spain, Sweden, Switzerland, Turkey, USSR, Yugoslavia.	Argentina, Aruba, Belize, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, Dominican Republic, Ecuador, El Salvador, French Guiana, Guatemala, Guyana, Haiti, Honduras, Jamaica, Mexico, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Surinam, Trinidad and Tobago, Uruguay, Venezuela.	Australia, China, Fiji Islands, Hong Kong, Indonesia, Japan, Korea, Malaysia, New Zealand, Papua New Guinea, Philippines, Singapore, Taiwan, Thailand.	Algeria, Angola, Bahrain, Bangladesh, Benin, Burkina Faso, Burundi, Cameroon, Central African Republic, Congo, Cote d'Ivoire, Egypt, Ethiopia, Gabon, Ghana, India, Iran, Iraq, Israel, Jordan, Kenya, Kuwait, Lebanon, Liberia, Libya, Madagascar, Mali, Mauritania, Mauritius, Morocco, Mozambique, Niger, Nigeria, Oman, Pakistan, Qatar, Reunion, Rwanda, Saudi Arabia, Senegal, Sierra Leone, Somalia, South Africa, Sri Lanka, Sudan, Syria, Tanzania, Togo, Tunisia, Uganda, United Arab Emirates, Yemen, Republic of Zaire, Zambia, Zimbabwe.

[FR Doc. 91.28913 Filed 12-2-91; 8:45 am]

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SECURITIES AND EXCHANGE COMMISSION

[Release No. 34-30003; File No. SR-NASD-91-64]

Self-Regulatory Organizations; Filing of Proposed Rule Change by National Association of Securities Dealers, Inc. Relating to Fees for Nasdaq Issuers

November 27, 1991.

Pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 ("Act"), 15 U.S.C. 78s(b)(1), notice is hereby given that on November 26, 1991, the National Association of Securities Dealers, Inc. ("NASD" or "Association") filed with the Securities and Exchange Commission ("SEC" or "Commission") the proposed rule change as described in Items I, II, and III below, which Items have been prepared by the NASD. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The NASD is herewith proposing a rule change to part IV of Schedule D to the NASD By-Laws to adopt a new annual fee for domestic Nasdaq National Market System ("Nasdaq/NMS") and Regular Nasdaq issuers (the "new annual fee"). The current language of part IV reflects the proposed rule change pending at the Commission in SR-NASD-91-56 as if adopted, which was published for comment in SEC Rel. No. 34-29916 (November 7, 1991). The new annual fee is proposed to be effective January 1, 1992. The NASD is proposing, however, to partially implement the new annual fee proposed in new paragraph 2 to renumbered sections B and E during calendar year 1992 with respect to domestic and foreign Nasdaq/NMS and Regular Nasdaq issues and to fully implement the new annual fee commencing January 1, 1993. The NASD is, therefore, also proposing to delete proposed paragraph 1 and the footnotes thereto and the words "As of January 1, 1992," to proposed paragraph 2 of renumbered sections B and E on December 31, 1992, in order to fully implement the new fee on January 1, 1993. No changes are proposed to the current annual fee for American Depositary Receipts ("ADRs"). Below is the text of the proposed rule change. Proposed new language is in italics; proposed deletions are in brackets.

Schedule D to the NASD By-Laws; Part IV; Listing Fees; the NASDAQ Stock Market-National Market System

A. Entry Fee

1. When an issuer submits an application for inclusion of any class of its securities in the National Market System, it shall pay to the Corporation:

a. A one-time company listing fee of $5,000 (which shall include a $1,000 nonrefundable processing fee) and;

b. For each class of security listed, a fee calculated on a graduated rate of $.005 per share for the first 5 million shares, $.0025 per share for each share between 5,000,001 and 15 million, inclusive, and $.001 per share for each share over 15 million, based on the total number of shares outstanding. Entry fees paid by a company for all classes of securities listed on the National Market System, regardless of the date those securities are listed, shall not exceed $50,000 (inclusive of the $5,000 company listing fee) [8]

* * * * *

B. Annual Fee—Domestic and Foreign Issues

[1. The issuer of each class of securities that is listed in the National Market System shall pay to the Corporation an annual fee to be computed as follows with a maximum annual fee of $8,000 per issuer:]

[a. a $2,000 National Market System participation fee; and,]

[b. the sum of $500 or $.0005 per share outstanding, whichever is higher, up to a maximum of $6,000 for each class of securities listed in the National Market System.[9]]

[2. The annual fee shall be based on the total amount of outstanding securities of the class included in the National Market System as shown in the issuer's most recent periodic report required to be filed with the issuer's appropriate regulatory authority and received by the Nasdaq Stock Market.]

1. The issuer of each class of securities that is a domestic or foreign issue listed in the National Market System shall pay to the Corporation an annual fee for 1992 that shall be calculated as follows:

(i) 100 percent of the current annual fee; [2]

[8] *For purposes of this Part, the term "shares" shall include common and preferred stock, American Depositary Receipts (ADRs), warrants, partnership interests, or any other security listed on the National Market System.*

[9] [Id.]

[2] *Current Annual Fee.*

1. The issuer of each class of securities that is a domestic or foreign issue listed in the National Market System shall pay to the Corporation an annual fee to be computed as follows with a maximum annual fee of $8,000 per issuer:

Continued

(ii) plus 50 percent of the difference between the current annual fee and the new annual fee set forth in paragraph 2.

2. As of January 1, 1993, the issuer of each class of securities that is a domestic or foreign issue listed in the National Market System shall pay to the Corporation an annual fee (comprised of a base annual fee and a variable annual fee) to be computed as follows:

a. The base annual fee shall be calculated on total shares outstanding [3] *according to the following schedule:*

Up to 1 million shares: $5,250
1+ to 2 million shares: $5,750
2+ to 3 million shares: $6,250
3+ to 4 million shares: $6,750
4+ to 5 million shares: $7,250
5+ to 6 million shares: $7,750
6+ to 7 million shares: $8,250
7+ to 8 million shares: $8,750
8+ to 9 million shares: $9,250
9+ to 10 million shares: $9,750
10+ to 11 million shares: $10,250
11+ to 12 million shares: $10,750
12+ to 13 million shares: $11,250
13+ to 14 million shares: $11,750
14+ to 15 million shares: $12,250
15+ to 16 million shares: $12,750
Over 16 million shares: $13,250

b. The variable annual fee shall be calculated at the rate of $.025 per $1,000 of market capitalization [4]*, but only for market capitalization above $100 million.*

c. The annual fee (comprised of the base and variable fees) shall be capped as follows:

For companies with 10 million shares or less: $10,000
For companies with 10+ to 20 million shares: $15,000
For companies with more than 20 million shares: $20,000

3. The Board of Governors or its designee may, in its discretion, defer or waive all or any part of the annual fee prescribed herein.

4. If a class of securities is removed from the National Market System, that portion of the annual fees for such class of securities attributable to the months following the date of removal shall not be refunded, *except such portion shall be applied to Regular Nasdaq fees for that calendar year.*

C. Annual Fee—American Depository Receipts (ADRs)

1. The issuer of each class of securities that is an ADR listed in the National Market System shall pay to the Corporation an annual fee to be computed as follows with a maximum annual fee of $8,000 per issuer;

a. a $2,000 National Market System participation fee; and,

b. the sum of $500 or $.0005 per share outstanding, whichever is higher, up to a maximum of $6,000 for each class of securities listed in the National Market System.

2. The annual fee shall be based on the total amount of outstanding securities of the class included in the National Market System as shown in the issuer's most recent periodic report required to be filed with the issuer's appropriate regulatory authority and received by the Nasdaq Stock Market.

3. The Board of Governors or its designee may, in its discretion, defer or waive all or any part of the annual fee prescribed herein.

4. If a class of securities is removed from the National Market System, that portion of the annual fees for such class of securities attributable to the months following the date of removal shall not be refunded, except such portion shall be applied to Regular Nasdaq fees for that calendar year.

Regular NASDAQ System

[C] *D. Entry Fee*

1. When an issuer submits an application for inclusion of any class of its securities in the Regular Nasdaq System, it shall pay to the Corporation:

* * * * *

b. for each class of securities listed, a fee to be computed as follows, with a maximum entry fee for all classes of securities listed, regardless of the date those securities are listed, of $10,000 per issuer (inclusive of the $5,000 company listing fee):

(i) Equity Securities—$1,000 or $.001 per share outstanding, whichever is higher. For purposes of this section, the term "equity securities" includes all securities eligible for inclusion in the Regular Nasdaq System not covered by subparagraph (ii) of this section.[[3]] [5]

* * * * *

[D.] *E. Annual Fee—Domestic and Foreign Issues*

[1. The issuer of each class of securities that is listed in the Regular Nasdaq System shall pay to the Corporation an annual fee to be computed as follows with a maximum annual fee of $6,000 per issuer;]

[(i) Equity Securities—$500 or $.0005 per share outstanding, whichever is higher.] [For purposes of this section, the term "equity securities" includes all securities eligible for inclusion in the Regular Nasdaq System not covered by paragraph (ii) of this section.[4]]

[(ii) Convertible Debentures—$500 or $25 per million dollars face amount of debentures outstanding, whichever is higher.]

[2. The annual fee shall be based on the total amount of outstanding securities of the class included in the Regular Nasdaq System as shown in the issuer's most recent periodic report required to be filed with the issuer's appropriate regulatory authority and received by the Nasdaq Stock Market.]

1. The issuer of each class of securities that is a domestic or foreign issue listed in the Regular Nasdaq System shall pay to the Corporation an annual fee for 1992 that shall be calculated as follows:

(i) 100 percent of the current annual fee [6]*;*

(ii) plus 50 percent of the difference between the current annual fee and the new annual fee set in paragraph 2.

2. As of January 1, 1993, the issuer of a class of securities that is a domestic or foreign issue listed in the Regular Nasdaq System shall pay to the Corporation an annual fee to be computed as follows;

(a) $4,000 for the first issue; plus

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a. a $2,000 National Market System participation fee; and,

b. the sum of $500 or $.0005 per share outstanding, whichever is higher, up to a maximum of $6,000 for each class of securities listed in the National Market System.

2. The annual fee shall be based on the total amount of outstanding securities of the class included in the National Market System as shown in the issuer's most recent periodic report required to be filed with the issuer's appropriate regulatory authority and received by the Nasdaq Stock Market.

[3] *Total shares outstanding shall be the aggregate of all classes of securities listed on the NMS calculated at year-end.*

[4] *Market capitalization is calculated by multiplying total shares outstanding at year end (except that convertible bonds, rights and warrants are not included) times the price at year end.*

[[3]] [5] [Id.] *Supra note 1.* In the case of units, each component, but not the unit itself, shall be considered separately as an "equity security" for fee purposes.

[[4] See supra notes 1 and 3.]

[6] *Current Annual Fee.*

1. The issuer of each class of securities that is a domestic or foreign issue listed in the Regular Nasdaq System shall pay to the Corporation an annual fee to be computed as follows with a maximum annual fee of $6,000 per issuer;

(i) Equity Securities—$500 or $.0005 per share outstanding, whichever is higher. For purposes of this section, the term "equity securities" includes all securities eligible for inclusion in the Regular Nasdaq System not covered by paragraph (ii) of this section.

(ii) Convertible Debentures—$500 or $25 per million dollars face amount of debentures outstanding, whichever is higher.

2. The annual fee shall be based on the total amount of outstanding securities of the class included in the Regular Nasdaq System as shown in the issuer's most recent periodic report required to be filed with the issuer's appropriate regulatory authority and received by the Nasdaq Stock Market.

(b) $1,000 for each additional issue.

3. The Board of Governors or its designee may, in its discretion, defer or waive all or any part of the annual fee prescribed herein.

4. If a class of securities is removed from the Regular Nasdaq System, that portion of the annual fees for such class of securities attributable to the months following the date of removal shall not be refunded, *except such portion shall be applied to National Market System fees for that calendar year.*

F. Annual Fee—American Depositary Receipts (ADRs)

1. The issuer of each class of securities that is an ADR listed in the Regular Nasdaq System shall pay to the Corporation an annual fee to be computed as follows with a maximum annual fee of $6,000 per issuer;

(i) Equity Securities—$500 or $.0005 per share outstanding, whichever is higher. For purposes of this section, the term "equity securities" includes all securities eligible for inclusion in the Regular Nasdaq System not covered by paragraph (ii) of this section.[7]

(ii) Convertible Debentures—$500 or $25 per million dollars face amount of debentures outstanding, whichever is higher.

2. The annual fee shall be based on the total amount of outstanding securities of the class included in the Regular Nasdaq System as shown in the issuer's most recent periodic report required to be filed with the issuer's appropriate regulatory authority and received by the Nasdaq Stock Market.

3. The Board of Governors, or its designee may, in its discretion, defer or waive all or any part of the annual fee prescribed herein.

4. If a class of securities is removed from the Regular Nasdaq System, that portion of the annual fees for such class of securities attributable to the months following the date of removal shall not be refunded, except such portion shall be applied to National Market System fees for that calendar year.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the NASD included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The NASD has prepared summaries, set forth in sections (A), (B), and (C) below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

The NASD has determined that an increase in the annual issuer fee for domestic and foreign listed companies on both Nasdaq/NMS and Regular Nasdaq is necessary to fund, among other things, increased market surveillance costs, significant enhancements to Nasdaq technology, enhanced product/service programs, and advertising programs for such issuers and markets. Under the proposed fee increases, Nasdaq issuers will continue to contribute a smaller percentage of revenue received by the NASD than the percentage of revenue contributed by New York Stock Exchange issuers to the NYSE. For calendar year 1990, Nasdaq issuers contributed 10.7 percent of total revenues received by the NASD compared to 34.2 percent contributed to total revenue of the New York Stock Exchange by NYSE issuers. For calendar year 1992, the NASD projects that total contributions by Nasdaq issuers, taking into consideration the proposed fee increases, shall only increase to approximately 16.7 percent of total revenues received by the NASD. The current annual fee for ADRs remains unchanged. Therefore, the structure of part IV to schedule D is proposed to be amended to renumber the sections to provide separate annual fee calculations for domestic and foreign issues and ADRs under the sections for Nasdaq/NMS and Regular Nasdaq. In addition, the NASD is proposing to amend the provisions which prohibit any refund of an annual fee for domestic and foreign issues and ADRs to provide an exception where the security moves from Nasdaq/NMS to Regular Nasdaq or from Regular Nasdaq to Nasdaq/NMS.

Calculation of Annual Fee in 1992

The new annual fee is proposed to be effective January 1, 1992. The NASD is proposing, however, to partially implement the new annual fee proposed in renumbered sections B and E during calendar year 1992 with respect to domestic and foreign NMS and Regular Nasdaq issues and to fully implement the new annual fee commencing January 1, 1993.

The NASD is proposing to include rule language setting forth the new annual fee in paragraph 2 of renumbered sections B and E, which is decribed separately below. The NASD is also proposing to add new paragraph 1 to renumbered sections B and E to include the method of calculating the annual fee for calendar year 1992 for domestic and foreign issues.

Proposed new paragraph 1 to renumbered sections B and E provides that, for calendar year 1992, the annual fee will be calculated on the basis of 100 percent of the current annual fee and 50 percent of the difference between the current annual fee set forth in the footnotes and the new annual fee which is set forth in paragraph 2. For example, a Nasdaq/NMS company that is subject to the current annual fee maximum of $8,000 and the new annual fee maximum of $20,000 would pay the $8,000 (current annual fee) plus $6,000 (50 percent of the difference—$12,000—between the $20,000 new annual fee and the $8,000 current annual fee) for a total of $14,000 for calendar year 1992.

The NASD is also proposing to delete paragraph 1 and the footnotes thereto, and the words "As of January 1, 1993," in paragraph 2 of renumbered sections B and E on December 31, 1992, to fully implement the new annual fee on January 1, 1993.

New Annual Fee—Domestic and Foreign Issues

National Market System: The current annual fee for Nasdaq/NMS issuers is comprised of a $2,000 participation fee and $500 or $.0005 per share outstanding, with a maximum total annual fee per issuer of $8,000. It is proposed that the new annual fee be calculated based on a base annual fee and a variable annual fee. The base annual fee would be calculated on total shares outstanding (total shares outstanding would be the aggregate of all classes of securities listed on Nasdaq/NMS, as is required by current rule language, with the clarification that the calculation is made at year end) according to the following schedule:

Up to 1 million shares: $5,250
1+ to 2 million shares: $5,750
2+ to 3 million shares: $6,250
3+ to 4 million shares: $6,750
4+ to 5 million shares: $7,250
5+ to 6 million shares: $7,750
6+ to 7 million shares: $8,250
7+ to 8 million shares: $8,750
8+ to 9 million shares: $9,250
9+ to 10 million shares: $9,750
10+ to 11 million shares: $10,250
11+ to 12 million shares: $10,750
12+ to 13 million shares: $11,250
13+ to 14 million shares: $11,750
14+ to 15 million shares: $12,250
15+ to 16 million shares: $12,750
Over 16 million shares: $13,250

[7] *See supra notes 1 and 5.*

The proposed variable annual fee would be calculated at the rate of $.025 per $1,000 of market capitalization, but only for market capitalization above $100 million. Market capitalization is calculated by multiplying total shares outstanding at year end (except that convertible bonds, rights and warrants are not included) times the price at year end.

The proposed new annual fee (comprised of the base and variable fees) would be capped as follows:

For companies with 10 million shares or less: $10,000

For companies with 10+ to 20 million shares: $15,000

For companies with more than 20 million shares: $20,000

Regular Nasdaq: The current annual fee for Regular Nasdaq issuers is $500 or $.0005 per share outstanding, with a maximum total annual fee per issuer of $6,000. It is proposed that the Regular Nasdaq annual fee be revised to charge a flat fee of $4,000 for the first issue plus $1,000 for each additional issue. The cap on the annual fee is proposed to be eliminated because, as a practical matter, the fee is minimal and issuers on Regular Nasdaq are unlikely to have more than 4 or 5 securities included in the system.

Refunds of Annual Fee

The current rule language of Schedule D prohibits the NASD from refunding that portion of the annual fees of a Nasdaq/NMS or Regular Nasdaq security attributable to the months following the date the security is removed from Nasdaq/NMS or Regular Nasdaq, respectively. This rule language does not reflect current practice with respect to companies that move from Nasdaq/NMS to Regular Nasdaq or from Regular Nasdaq to Nasdaq/NMS. The NASD proposes that the refund provisions related to the NMS be amended to clarify that where a security moves from the NMS to Regular Nasdaq, any such portion of the annual NMS fee shall be applied to Regular Nasdaq annual fee for that calendar year. The NASD also proposes that the refund provisions related to Regular Nasdaq be amended to clarify that where a security moves from Regular Nasdaq to NMS, any such portion of the annual Regular Nasdaq fees shall be applied to the NMS annual fee for that calendar year. This proposed amendment applies to both domestic and foreign issues and ADRs.

The NASD believes the proposed rule change is consistent with the provisions of section 15A(b)(5) of the Act, which requires that the Association provide for the equitable allocation of reasonable dues, fees, and other charges among members and issuers and other persons using any facility or system which the Association operates or controls.

B. Self-Regulatory Organization's Statement on Burden on Competition

The NASD does not believe that the proposed rule change will result in any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act, as amended.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received from Members, Participants, or Others

Written comments were neither solicited nor received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Within 35 days of the date of publication of this notice in the Federal Register or within such longer period (i) as the Commission may designate up to 90 days of such date if it finds such longer period to be appropriate and publishes its reasons for so finding or (ii) as to which the self-regulatory organization consents, the Commission will:

A. By order approve such proposed rule change, or

B. Institute proceedings to determine whether the proposed rule change should be disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing. Persons making written submissions should file six copies thereof with the Secretary, Securities and Exchange Commission, 450 Fifth Street, NW., Washington, DC 20549. Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule change that are filed with the Commission, and all written communications relating to the proposed rule change between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5 U.S.C. 552, will be available for inspection and copying in the Commission's Public Reference Room. Copies of such filing will also be available for inspection and copying at the principal office of the NASD. All submissions should refer to the file number in the caption above and should be submitted by December 24, 1991.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority, 17 CFR 200.30-3(a)(12).

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 91-28993 Filed 12-2-91; 8:45 am]

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[Release No. 34-29990; File No. SR-OCC-91-18 and File No. SR-ICC-91-01]

Self-Regulatory Organizations; the Options Clearing Corp., and the Intermarket Clearing Corp.; Filing and Order Granting Accelerated Approval of Proposed Rule Changes Relating to Calculation of Additional Margin

November 26, 1991.

Pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 ("Act"),[1] notice is hereby given that on November 22, 1991, the Options Clearing Corporation ("OCC") and the Intermarket Clearing Corporation ("ICC") (sometimes collectively referred to in this notice as the "Clearing Corporations") filed with the Securities and Exchange Commission ("Commission") the proposed rule changes as described in Items I, II, and III below, which items have been prepared by the Self-regulatory organizations. This order grants accelerated approval of the proposals.

I. Self-Regulatory Organizations' Statement of the Terms of Substance of the Proposed Rule Change

The purpose of the proposed rule changes is to incorporate an alternative minimum "additional margin" requirement into OCC's Rules and into ICC's Board Resolution.

II. Self-Regulatory Organizations' Statement for the Purpose of, and Statutory Basis for, the Proposed Rule Changes

In their filings with the Commission, the self-regulatory organizations included statements concerning the purpose of and statutory basis for the proposed rule changes and discussed any comments they received on the proposed rule changes. The texts of these statements may be examined at the places specified in Item IV below. The self-regulatory organizations have prepared summaries, set forth in sections (A), (B), and (C) below, of the most significant aspects of such statements.

[1] 15 U.S.C. 78s(b)(1).

A. Self-Regulatory Organizations' Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Changes

1. General Purpose of the Proposed Rule Changes

The purpose of the proposed rule changes is to modify OCC's Rules describing the calculation of margin [2] and ICC's Board Resolution [3] describing the calculation of margin to incorporate an alternative minimum "additional margin" requirement into the Clearing Corporations' margin systems. Both Clearing Corporations utilize the Theoretical Intermarket Margin System ("TIMS").[4] The alternative calculation is designed to assure that TIMS generates at least a small additional margin requirement for each Clearing Member account at OCC and ICC in which short positions or long positions that are eligible for margin credit are being carried. The alternative margin calculation will require additional margin even in an account in which, for purposes of the current TIMS calculation of additional margin, the value of the long positions in the account that are eligible for margin credit equals or exceeds the value of the short positions in the account. (Such an account is referred to below as an account that is "hedged.")

The function of the additional margin component of the TIMS margin calculation is to provide an additional margin cushion to protect the Clearing Corporations against two conceptionally distinguishable but closely related types of risk. These risks are: (1) The risk of a market move that decreases the value of a suspended Clearing Member's positions during the time between the final collection of margin by the Clearing Corporations assessed prior to the suspension of the Clearing Member and the actual closing-out or hedging by the Clearing Corporations of the suspended Clearing Member's short positions and long positions against which margin credit has been given ("market risk"); and (2) the risk that in buying-in the suspended Clearing Member's short positions and in closing-out the suspended Clearing Member's long positions against which margin credit has been given, the Clearing Corporations will find themselves forced to conduct the close-out transactions at unfavorable market prices ("liquidation risk"). OCC and ICC believe that TIMS currently computes additional margin requirements that adequately protect the Clearing Corporations against both market risk and liquidation risk. However, the staff of the Commission has expressed concern that the current TIMS calculations may not require adequate additional margin to protect the Clearing Corporations, particularly against liquidation risk, with respect to hedged accounts. The changes in TIMS proposed in these rule filings are intended to allay this concern.

2. Purpose of Additional Margin and Overview of Its Calculation

Both Clearing Corporations require their Clearing Members to adjust their margin deposits with the Clearing Corporations in the morning on every business day based on calculations performed the night before. Both Clearing Corporations impose a margin requirement on short positions in each Clearing Member account and give margin credit in respect of long positions that are eligible for margin credit. Under TIMS, the margin requirement or credit for positions in a "class group" [5] that is not part of a "product group" [6] in a given Clearing Member account is equal to the "premium margin" [7] amount for the positions increased (in the case of a negative liquidating value) or decreased (in the case of a positive liquidating value) by the "additional margin" amount for that class group. Similarly, the margin requirement or credit for a product group is equal to the algebraic sum of the premium margin requirements and credits for the class groups in the product group increased (in the case of a negative liquidating value) or decreased (in the case of a positive liquidating value) by the "additional margin" amount for that product group.

TIMS calculates "additional margin" by using options price theory to determine the impact of an increase or decrease in the market value of the interest underlying the class group less than or equal to the applicable "margin interval." [8] The additional margin for a class group is essentially the amount or margin that would protect the Clearing Corporation from the greatest possible loss that could arise from a change, in either direction up to or equal to the margin interval, in the market value of the interest underlying the class group. The additional margin calculation for a product group differs only slightly from the calculation of additional margin for a class group. In calculating the additional margin for a product group, the Clearing Corporations reduce the credit to be given for any calculated increase in the value of the positions in one class group by a preset percentage applicable to the product group before applying the credit to offset the decrease in the value of the positions in another class group in the same product group.

3. Description of the Alternative Minimum Additional Margin Calculation

These proposed rule changes would provide that TIMS would compute an alternative minimum margin amount for each product group in a Clearing Member's account at OCC and ICC. The calculation will be as follows: (1) For each "net" [9] short position in securities

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[2] The calculation of OCC margin requirements are set forth in OCC Rule 601 for equity options and OCC Rule 602 for non-equity options and commodity options and futures which are subject to margin at OCC because of a cross-margin program with a commodity clearing organization other than ICC.

[3] ICC Margin Resolution section 3, ICC Board Resolution, November 19, 1991.

[4] For a detailed description of TIMS, see Securities Exchange Act Release No. 29828 (March 1, 1991), 56 FR 9995.

[5] At OCC, A "class group" consists of all put and call options having the same underlying interest. A class group also consists of commodity options and futures which are subject to margin at OCC because of a cross-margin program with a commodity clearing organization and which relate to the same underlying interest. Upon the Commission's approval of File No. SR-OCC-91-5, the term class group will also include Index Participations ("IPs"). OCC rules 601(b)(2) and 602(b)(2).

At ICC a "class group" consists of commodity options and futures relating to the same underlying interest and put and call securities options having the same underlying interest which are subject to margin at ICC because of ICC's cross-margin program with OCC.

[6] A "product group" consists of all class groups having underlying assets determined by the Clearing Corporations to exhibit price correlation sufficient to warrant margining on a combined basis. OCC rule 602(b)(3). See also OCC Rule 601(b)(3).

[7] The "premium margin" requirement or credit is the liquidating value of the positions based on premium levels at the close of trading on the preceding trading day. OCC rules 601(b)(4) and 602(b)(4).

[8] The applicable "margin interval" is the effect on the value of the positions in each class group based on a projected maximum one-day price movement in the underlying interest that the Clearing Corporations desire to protect against. OCC rules 601(b)(8) and 602(b)(8).

[9] The "net" position in an option series in an account is the position resulting from offsetting the gross long position in that series that is entitled to margin credit against the gross short position in that series. After netting, an account will reflect a net short position or a net long position for each series of options held in the account. Similarly, for additional margin purposes, the net position in a futures contract in an account is the position resulting from offsetting the gross long position in the contract against the gross short position for each delivery month and then paring the remaining positions into intermonth spreads. In a close-out, the Clearing Corporation effecting the close-out should be exposed to liquidation risk only with respect to the net long or short position because (1) OCC and ICC may offset long and short positions carried by a suspended Clearing Member in the same series of options against each other, (2) ICC may offset long and short positions carried by a suspended Clearing

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options, IPs, or commodities options in the product group and for each net long or short positions in futures in the product group, the number of contracts in the net positions would be multiplied by an eighth of a point, and that result would be multiplied by the applicable unit of trading, index multiplier, or multiplier; (2) for each net long securities option, IP, or commodities option position in the product group, the number of contracts in the net long position would be multiplied by the lesser of an eighth of a point or the value of the premium margin credit for the net long position,[10] and that result would be multiplied by the applicable unit of trading, index multiplier, or multiplier; (3) the values determined pursuant to steps (1) and (2) for all net short and all net long positions would be added together; and (4) if the value determined for a product group pursuant to step (3) is greater than the amount calculated by the current TIMS additional margin calculation, the value determined pursuant to step (3) would be the additional margin amount for the product group. OCC and ICC have concluded that the one-eighth of a point value described in steps (1) and (2) provides an ample alternative minimum additional margin calculation with respect to any risks to them posed by hedged accounts.

4. Statutory Basis

The Clearing Corporations believe that the proposed rule changes are consistent with section 17A of the Act, because they provide for an alternative additional margin computation that increases the amount of additional margin required by TIMS in some circumstances in which a higher additional margin requirement may enhance TIMS's protection to the Clearing Corporations. The proposed rule changes therefore help to guarantee the liquidity of the Clearing Corporations and to provide for the safeguarding of funds and securities in the Clearing Corporations' custody or control or for which the Clearing Corporations are responsible.

B. Self-Regulatory Organizations' Statement on Burden on Competition

OCC and ICC do not believe that the proposed rule changes will impose any burden on competition.

C. Self-Regulatory Organizations' Statement on Comments on the Proposed Rule Changes Received From Members, Participants or Others

Comments concerning the proposed rule changes were not and are not intended to be solicited by OCC or ICC with respect to the proposed rule changes, and none have been received by OCC or ICC.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Sections 17A(b)(3) (A) and (F) [11] of the Act requires that a clearing agency must be organized and its rules designed to assure the safeguarding of securities and funds in the clearing agency's custody or control or for which the clearing agency is responsible. The Commission believes that the proposals will enhance the financial security of the Clearing Corporations by instituting within TIMS an alternative additional margin computation that is designed to reflect the potential for additional loss in liquidating open contracts held for a defaulting or insolvent Clearing Member. Although TIMS can project that two positions should offset under ideal conditions, difficulties in liquidating both sides of a combined position can occur, thereby increasing exposure to the Clearing Corporations which may not be accounted for completely within the TIMS margin system. For example, it is possible that one side of a combined position (*e.g.*, the stock index futures side of a stock index future-stock index option combined position) might be left at a time when the market for that position may be closed, but the market for the components of the index underlying that position (*e.g.*, S & P 100) continues to trade and prices and index values move adversely to the remaining position. The Commission believes that the proposals help the Clearing Corporations assure the safeguarding of securities and funds in the Clearing Corporations' custody or control or for which they are responsible.

OCC and ICC have requested that the Commission find good cause for approving the proposed rule changes prior to thirty days after the date of publication of this notice in the **Federal Register.** OCC and ICC intend to implement the proposals concurrent with the implementation of their proposed non-proprietary cross-margin programs.[12]

The Commission finds good cause for approving the proposed rule changes because the Commission believes that the proposed rule changes should be approved prior to or contemporaneously with approval of OCC's and ICC's proposed rule changes relating to cross-margining of certain non-proprietary accounts. Because the proposed rule changes will establish an alternative additional margin computation that will require a minimum margin for each cross-margin account, accelerated approval of the proposals should result in greater protection to the Clearing Corporations and to the securities and funds in their custody or control or for which they are responsible when the OCC/ICC non-proprietary cross-margin program is implemented. Although notice of these proposed rule changes did not appear in the **Federal Register**, notices of the proposed rule changes relating to the OCC/ICC non-proprietary cross-margin program have appeared in the **Federal Register**,[13] and the Commission does not believe that these proposed rule changes present any major substantive issues that are not addressed by the OCC/ICC non-proprietary cross-margin program filings.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing. Persons making written submissions should file six copies thereof with the Secretary, Securities and Exchange Commission, 450 Fifth Street, NW., Washington, DC 20549. Copies of the submission, all subsequent amendments, all written statements with respect to the proposed rule changes that are filed with the Commission, and all written communications relating to the proposed rule changes between the Commission and any person, other than those that may be withheld from the public in accordance with the provisions of 5

Member in the same future, and (3) in the case of an OCC cross-margin program with a commodity clearing organization other than ICC, the commodity clearing organization may offset long and short positions in futures and long and short positions in commodity options against each other or close-out the positions simultaneously.

[10] The proposed rule change provides that the amount of the alternative minimum additional margin requirement for a net long securities option, IP, or commodities option position can be no greater than the premium margin credit generated by the long position in order to avoid the anomalous possibility that the alternative minimum additional margin requirement could generate a net margin requirement for a long options position.

[11] 15 U.S.C. 78q–1(b)(3)((A) and (F).

[12] Securities Exchange Act Release No. 27717 (February 21, 1990) 55 FR 7398 [File No. SR–OCC–90–1] (notice of proposed rule change relating to the OCC non-proprietary cross-margin program with the Chicago Mercantile Exchange). Securities Exchange Act Release No. 28205 (July 16, 1990), 55 FR 30349 [File Nos. SR–OCC–90–4 and SR–ICC–90–3] (notice of proposed rule changes relating to the OCC/ICC non-proprietary cross-margin program.

[13] *Id.*

U.S.C. 552, will be available for inspection and copying in the Commission's Public Reference Section, 450 Fifth Street, NW., Washington, DC 20549. Copies of such filing will also be available for inspection and copying at the principal offices of the above-mentioned self-regulatory organizations. All submissions should refer to the File Nos. SR-OCC-91-18 and SR-ICC-91-01 and should be submitted by December 24, 1991.

V. Conclusion

On the basis of the foregoing, the Commission finds that the proposed rule changes are consistent with the Act and, in particular, with section 17A of the Act.

It is therefore ordered, under section 19(b)(2) of the Act,[14] that the proposed rule changes (File Nos. SR-OCC-91-18 and SR-ICC-91-01) be, and hereby are, approved.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[15]

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 91-28933 Filed 12-2-91; 8:45 am]

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[14] 15 U.S.C. 78s(b)(2).

[15] 17 CFR 200.30-3(a)(12).

[Release No. 34-29991; File No. SR-OCC-90-01]

November 26, 1991.

Self-Regulatory Organizations; The Options Clearing Corp.; Order Approving a Proposed Rule Change To Expand the OCC/CME Cross-Margin Program to Market Professionals on a Temporary Basis Through November 30, 1993

I. Introduction

On January 30, 1990, The Options Clearing Corporation ("OCC") submitted a proposed rule change (SR-OCC-90-01) to the Securities and Exchange Commission ("Commission") pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 ("Act"),[1] to expand the OCC/Chicago Mercantile Exchange ("CME") cross-margin program to include futures and options positions held by Clearing Members for certain market professionals. Notice of the proposed rule change was published for comment in the **Federal Register** on February 21, 1990.[2] Two comment letters were received. OCC amended the proposal on June 10, 1991,[3] on October 23, 1991, and on November 26, 1991.[4] As discussed below, the Commission is approving OCC's proposal on a temporary basis through November 30, 1993.

II. Description

In its present form, the OCC/CME cross-margin program ("Proprietary Cross-Margin Program") is limited to the cross-margining of proprietary accounts.[5] OCC's proposal expands the program to non-proprietary accounts carried by participating Clearing Members on behalf of "Market Professionals" ("Non-Proprietary Cross-Margin Program"). OCC defines a "Market Professional" as: (i) Any market maker,[6] specialist,[7] or registered trader,[8] as defined in OCC's Rules, and (ii) any CME member to the extent that the member is trading for the member's account and not for others.[9]

OCC's proposal consists of the Agreement, Non-Proprietary Cross-Margin Account Agreement and Security Agreement for participating Clearing Members, Subordination Agreement for OCC-CME Cross-Margining, and conforming changes to other OCC Account Agreements, By-laws, and Rules. OCC's proposal generally retains the structure and mechanics of the Proprietary Cross-Margin Program. However, OCC's proposal to expand cross-margining to Market Professionals addresses concerns regarding segregation and liquidation procedures under the Commodity Exchange Act ("CEA"),[10] the Bankruptcy Code,[11] and the Securities Investor Protection Act ("SIPA")[12] as discussed in more detail below.

As with OCC's Proprietary Cross-Margin Program, OCC's Non-Proprietary Cross-Margin Program would be available to OCC Clearing Members that carry the accounts of Market Professionals and that are also Clearing Members of the CME ("Joint Clearing Members") or that have affiliates that are members of the CME ("Affiliated Clearing Members"). Contracts eligible for the Non-Proprietary Cross-Margin Program are the same as those eligible for the Proprietary Cross-Margin Program.[13] In addition, the procedures

[1] 15 U.S.C. 78s(b)(1)(1988).

[2] Securities Exchange Act Release No. 27717, (February 21, 1990), 55 FR 51365.

[3] OCC, among other things, amended section 24(b) of Article VI of its By-laws to provide explicitly that OCC had authority to share with CME information not only about Clearing Members that maintain cross-margin accounts but also about any "affiliate" of the Clearing Member that is also a Clearing Member. The definition of "affiliate" would include certain vertical relationships, whether direct or through an intermediate entity, and would permit the inclusion of other relationships where OCC and CME agree that the financial condition of the related Clearing Member could have a material impact on the financial condition of the cross-margining Clearing Member.

[4] On October 23, 1991, OCC filed revised versions of the various non-proprietary cross-margin agreements. Among other modifications, changes were made to the Amended and Restated Cross-Margin Agreement ("Agreement") to: (1) Acknowledge that there are situations where initial margin deposits can be applied by OCC or CME to meet the obligations of the Clearing Member rather than be returned to the Clearing Member (Section 6, paragraphs (b) and (c)); (2) provide for disputed transfer instructions regarding daily settlement (Section 7); (3) make clear that OCC and CME could agree to transfer rather than liquidate contracts carried in the non-proprietary cross-margin accounts of a suspended Clearing Member (Section 8, paragraph (a)); and (5) reflect that surplus funds from the liquidation of a proprietary cross-margin account can be applied to any losses of either OCC or CME arising from the default of the Clearing Member (Section 8, paragraph (d)).

On November 26, 1991, OCC amended proposed Section 1(tttt) of article I of its By-laws to change, in part, the definition of Market Professional from "any member of a [commodities clearing organization]" to "any CME member."

[5] For a detailed description of the Proprietary Cross-Margin Program, see Securities Exchange Act Release No. 27296 (September 26, 1989), 54 FR 41195 ("Proprietary Cross-Margin Order").

[6] A "market maker" is any member of a national securities exchange who is acting as a market maker in an exchange transaction pursuant to the rules of the exchange. OCC By-laws, article I, section 1(u).

[7] A "specialist" is any member of a national securities exchange who is acting as a specialist, or group of members of an exchange acting as a specialist unit, in an exchange transaction pursuant to the rules of the exchange. OCC By-laws, article I, section 1(v).

[8] A "registered trader" is any member of a national securities exchange which is acting as a registered trader in an exchange transaction pursuant to the rules of the exchange and a floor trading activities plan filed with and declared effective by the Commission. OCC By-laws, article I, section 1(jjj).

[9] OCC By-laws, article I, section 1(tttt).

[10] 7 U.S.C. 1-26 (1988).

[11] 11 U.S.C. 1, *et al.*, as amended (1988).

[12] 15 U.S.C. 78aaa-78111 (1988).

[13] OCC put and call option contracts eligible for cross-margining are:

1. S&P 100 Index;
2. S&P 500 Index;
3. Major Market Index;
4. New York Stock Exchange Composite Index;
5. Financial News Composite Index; and
6. Institutional Index.

CME contracts eligible for cross-margining are:

1. S&P 500 Index Futures; and
2. Put and call options on the S&P 500 Index Futures.

Any change in the list of eligible contracts must be filed with the Commission for review under Section 19(b) of the Act.

for margin and premium settlements remain substantially the same [14] except that positions held for market professionals must be maintained in an independent market-maker cross-margin account which will be distinct from the proprietary cross-margin account.

OCC's proposal to extend cross-margining to Market Professionals modifies the Proprietary Cross-Margin Program to accommodate certain CEA segregation requirements and to avoid conflicting distribution schemes in the event of a Clearing Member liquidation. Pursuant to CEA requirements, the property of customers must be segregated from the proprietary property of a futures commission merchant ("FCM").[15] Because Market Professionals are considered "customers" under Commodity Futures Trading Commission ("CFTC") regulations,[16] their cross-margined positions and all property relating thereto must be segregated from the cross-margined positions and property of the Clearing Member who carries their accounts.

Under the proposal, each Clearing Member electing to participate in the Non-Proprietary Cross-Margin Program must execute a Non-Proprietary Cross-Margin Agreement and Security Agreement and must establish a separate cross-margin account for the benefit of the Market Professionals for whom it carries cross-margined positions ("Non-Proprietary Cross-Margin Account"). Clearing Members that establish Non-Proprietary Cross-Margin Accounts must also obtain the consent of each Market Professional whose cross-margined positions are carried in such account to the commingling of the Market Professional's assets with those of other electing Market Professionals.[17] Moreover, because section 4d(2) of the CEA [18] prohibits commingling futures and securities in the absence of a CFTC rule, regulation, or order to the contrary, the CFTC today has issued an order ("CFTC Order") [19] that will allow, under certain conditions, Clearing Members to commingle money, securities, and property received by a Clearing Member to margin, guarantee, or secure non-proprietary cross-margin options and futures contracts.[20]

OCC also has established certain procedures to facilitate the segregation of the money, securities, and other property deposited or received by Clearing Members regarding their non-proprietary cross-margin activity from the securities, money, and other property deposited or received regarding their proprietary cross-margin activity. For example, each Clearing Member must establish separate bank accounts for the purpose of making daily money

[14] To participate in cross-margining, eligible OCC/CME Clearing Members must establish cross-margining accounts at both OCC and CME. Each Joint Clearing Member and each pair of Affiliated Clearing Members must designate either OCC or CME as its Designated Clearing Organization ("DCO"). The DCO will provide each Joint Clearing Member and Affiliated Clearing Member with a daily margin and settlement report and will perform settlement functions on behalf of itself and the other clearing organization in connection with the cross-margin accounts. For a more extensive description of the cross-margining system, see Proprietary Cross-Margin Order.

Settlement will occur on a daily basis through a joint OCC-CME settlement account. OCC and CME will exchange reports on positions and settlements prior to the opening of the markets on each business day. After they exchange reports of positions, OCC and CME will calculate the members' margin requirements. The DCO for each Joint Clearing Member or pair of Affiliated Clearing Members will then issue a report stating the margin requirements and the netted settlement obligations. *Id.* at 41198.

[15] 7 U.S.C. 6d(2) (1988).

[16] For the purposes of determining whether a person is a "customer" of an FCM, CFTC Regulation § 1.3(k) (17 CFR 1.3(k) (1991)) provides that the owner or holder of a "proprietary account" is not a customer of an FCM within the meaning of section 4d(2) of the CEA (7 U.S.C. 6d(2) (1988)) and the rules and regulations thereunder. CFTC Regulation § 1.3(y) (17 CFR 1.3(y) (1991)) defines a "proprietary account" as one of which at least 10% or more is owned by one of the following persons: (1) The FCM itself; (2) a general partner of the FCM; (3) a limited or special partner but only if his duties include management of the partnership, handling of customer trades or funds, recordkeeping of customer trades or funds, or execution of the FCM's checks or drafts; (4) an officer, director, or owner of 10% or more of the capital stock of a corporate FCM; (5) an employee having the duties of the nature described above for limited or special partners; (6) a spouse or minor dependent living in the same household as any of the foregoing; (7) a controlling business affiliate of the FCM; or (8) a business affiliate controlled by or under common control with the FCM. All other persons, including Market Professionals not falling within CFTC Regulation § 1.3(y) (17 CFR 1.3(y) (1991)), are deemed to be customers of the FCM.

[17] Pursuant to section 4d(2) of the CEA, for convenience an FCM may commingle and deposit customer money, securities, and property in the same account at a bank, trust company, or clearing organization. 7 U.S.C. 6d(2) (1988). The funds and profits of one customer, however, may not be used to margin, guarantee, or settle the trades of another customer. 17 CFR 1.22 (1991).

[18] 7 U.S.C. 6d(2) (1988).

[19] CFTC Order (November 26, 1991), 56 FR

[20] CFTC Regulations 1.20(a), 1.22, and 1.24 (17 CFR 1.20(a), 1.22, and 1.24 (1991)) prohibit the commingling of customer futures funds with customer non-futures funds. The CFTC Order modifies those restrictions on the following conditions:

(1) Each participating Clearing Member and Market Professional execute all necessary Non-Proprietary Cross-Margin agreements;

(2) Each participating Clearing Member separately account for property maintained in Non-Proprietary Cross-Margin Accounts and not commingle such property with money, securities, and property maintained in any non-cross-margin accounts or proprietary cross-margin accounts;

(3) Each participating Clearing Member provide the CFTC with access to its books and records with respect to Non-Proprietary Cross-Margin Accounts and positions;

(4) Each participating Clearing Member include all cross-margin property received from participating Market Professionals to margin, guarantee, or secure commodity transactions or securities options transactions, or accruing to such participating Market Professionals as a result of such transactions, when calculating segregation requirements for purposes of section 4d of the CEA;

(5) Each participating Clearing Member compute total segregation requirements under section 4d of the CEA and CFTC Regulation 1.32 (17 CFR 1.32 (1991)) by calculating separately the requirements for cross-margin accounts and non-cross-margin accounts without using any net liquidation equity in one account to reduce a deficit in the other;

(6) Each participating Clearing Member designate Non-Proprietary Cross-Margin Accounts and Non-Proprietary Cross-Margin positions as such in its books and records and in the account statements sent to participating Market Professionals;

(7) Each participating Clearing Member calculate and collect the margin requirements for each Non-Proprietary Cross-Margin Account separately from the margin requirements for other accounts, including proprietary cross-margin accounts; collect any margin required with respect to Non-Proprietary Cross-Margin Accounts separately without applying any margin in any such account to satisfy a margin requirement in any proprietary account or any non-cross-margin customer account and without applying any margin in a non-cross-margin customer account to satisfy a margin requirement in any proprietary account or any Non-Proprietary Cross-Margin Account; and maintain all cross-margin property received from participating Market Professionals to margin, guarantee, or secure commodity transactions or securities options transactions that are effected for Non-Proprietary Cross-Margin Accounts or held in such accounts, and all accruals resulting from such transactions, separately from money, securities, and property received to margin, guarantee, or secure commodity transactions or securities options transactions that are effected for or held in any proprietary account or any non-cross-margin customer account and related accruals; and

(8) Each participating Clearing Member satisfy any deficiency in a Non-Proprietary Cross-Margin Account without recourse to non-cross-margin segregated funds.

The CFTC Order, however, allows Clearing Members to commingle cross-margin property maintained in respect of the Non-Proprietary Cross-Margin Program with money, securities, and property maintained in respect of other non-proprietary cross-margin programs between OCC and other commodity clearing organizations or between CME and other commodity clearing organizations approved by the CFTC, and may apply such commingled money, securities, and property to meet its obligations to a commodity or options clearing organization arising from trades or positions held in its Non-Proprietary Cross-Margin Account established pursuant to one or more such cross-margin programs. Such commingling is permitted only if the participating Clearing Member: (1) Separately identifies and accounts for the money, securities, and property held pursuant to each of the non-proprietary cross-margin programs separately from property held in other non-proprietary cross-margin accounts; and (2) separately calculates the margin requirements for each non-proprietary cross-margin program, treating each position as being held pursuant to only one such arrangement.

settlement of its proprietary cross-margin activity and of its non-proprietary cross-margin activities. In addition, OCC and CME will establish and use two separate joint bank accounts, one for paying and collecting cash margin and money settlement amounts resulting from Clearing Members' proprietary cross-margin activities and one for paying and collecting cash margin and money settlement amounts resulting from Clearing Members' non-proprietary cross-margin activity. OCC will not permit the netting of obligations arising out of a Clearing Member's proprietary cross-margin activity with those arising out of its non-proprietary cross-margin activity.

OCC also has taken steps to assure the segregation of United States Treasury securities and common stocks that are deposited with OCC, CME, or their agents to satisfy margin requirements in Non-Proprietary Cross-Margin Accounts and proprietary cross-margin accounts. For example, OCC and CME will establish and use two separate joint accounts, one for proprietary cross-margin activity and one for non-proprietary cross-margin activity, to hold United States Treasury securities deposited as margin by Clearing Members. In addition, common stock deposited as margin for Clearing Member's non-proprietary cross-margin activity will be held at The Depository Trust Company in an account which is designated as containing segregated customer assets.

OCC's proposal also modifies the Proprietary Cross-Margin Program to address the potential for conflict between SIPA [21] and the corresponding CFTC bankruptcy regulations [22] in the event of the liquidation and distribution of the property and funds of an OCC Clearing Member who is a registered broker-dealer.[23] To establish uniform results in the event of the liquidation of a broker-dealer Clearing Member under SIPA, OCC will require each Market Professional electing to participate in the Non-Proprietary Cross-Margin Program to agree that in the event of the bankruptcy or liquidation of the Clearing Member that carries its cross-margined positions, the Market Professional will subordinate its cross-margin related claims to the claims of the Clearing Member's non-cross-margining customers.[24] Similarly, each participating Market Professional must acknowledge that all of the assets carried in a Clearing Member's Non-Proprietary Cross-Margin Account on the Market Professional's behalf will not be deemed "customer property" for the purposes of SIPA or give rise to any claim thereunder. This means in the event of a Clearing Member bankruptcy all claims to assets in cross-margining accounts are to be determined under subchapter IV of the Bankruptcy Code [25] and applicable CFTC regulations.[26] In addition, each of these measures reduces the possibility that the assets in a Clearing Member's Non-Proprietary Cross-Margin Account will be subject to two potentially conflicting schemes of distribution.[27]

In the event of a Clearing Member default, OCC/CME will follow the same remedies as outlined in the Proprietary Cross-Margin Order to liquidate the proprietary and non-proprietary cross-margin accounts. Any deficit in the Non-Proprietary Cross-Margin Account would be offset against any credit in the proprietary cross-margin account. Non-cross-margin accounts at OCC/CME would be liquidated or transferred pursuant to OCC or CME procedures as they exist today.[28] OCC and CME will not offset a credit in the Non-Proprietary Cross-Margin Account with a deficit in the proprietary cross-margin account or with any other account OCC or CME maintains for the defaulting Clearing Member. Thus, any surplus in the Non-Proprietary Cross-Margin Account will be returned to the Clearing Member or its representative.

In the event of a Clearing Member bankruptcy, OCC and CME will be exempt from the automatic stay and will be permitted to liquidate any assets held for the insolvent Clearing Member.[29] Subject to the limitations discussed above concerning the treatment of customer and non-lien property, OCC and CME will be permitted to offset those assets against the Clearing Member's liabilities to the respective organizations. The process for and limitations on the liquidation and offset in accounts held by an insolvent Clearing Member is the same as the process and limitations described for a defaulting Clearing Member. The assets of the Clearing Member held in the Non-Proprietary Cross-Margin Account therefore will be set-off only against related non-proprietary cross-margining liabilities. Any assets remaining after such a set-off will be transferred to the bankruptcy trustee for administration and distribution.[30]

If a Joint Clearing Member becomes insolvent, SIPC may and probably will have the power to file for a protective decree under SIPA.[31] SIPC will then appoint a trustee charged with liquidating the bankrupt estate, consistent with SIPA and SIPC by-laws.[32] Under SIPA, the trustee must administer the assets of the Joint Clearing Member held as a commodity broker in accordance with the Bankruptcy Code's commodity broker liquidation requirements [33] and applicable CFTC regulations.[34] Even if

[21] 15 U.S.C. 78aaa–78lll (1988).

[22] 17 CFR 190.01–.10 (1991).

[23] Most Market Professionals, as registered broker-dealers or "specialists" in their own right, would not be "customers" within the meaning of SIPA or Rule 15c3–3 under the Act (17 CFR 240.15c3–3 (1991)). Some commodity clearing corporation members trading in OCC issued options for their own account could be deemed "customers" under either SIPA or Rule 15c3–3 if those positions are carried on the books of broker-dealers. Both types of market professionals, however, will be required to agree, as stated above, to subordinate their claims in a clearing member broker-dealer insolvency to the claims of other customers.

[24] Under SIPA, the Securities Investor Protection Corporation ("SIPC") satisfies the claims of "customers" against insolvent broker-dealers up to predetermined limits. 15 U.S.C. 78fff–3 (1988). Under SIPA, however, the term "customer" does not include any person to the extent that such person has a claim for cash or securities which, by agreement, is subordinated to the claims of any or all creditors of the debtor. 15 U.S.C. 78lll(2)(B) (1988). Because a Market Professional will be required to subordinate its cross-margin related claims against a Clearing Member to those of the Clearing Member's non-cross-margining customers, it will not fall within the protection afforded by SIPA. Letter from Michael E. Don, Deputy General Counsel, SIPC, to Ross Pazzol, Attorney Adviser, Division of Market Regulation ("Division"), Commission (July 16, 1990).

[25] 11 U.S.C. 761–766 (1988).

[26] 17 CFR 190.01–10 (1991).

[27] Currently, 48 of OCC's 143 Clearing Members are also registered as FCMs.

[28] Pursuant to OCC Rule 1104(a), "[U]pon the suspension of a Clearing Member, [OCC] shall promptly convert to cash, in the most orderly manner practicable, all margins deposited with [OCC] by such Clearing Member in all accounts . . . and all of such Clearing Member's contributions to the Clearing Fund * * *." For a detailed explanation of OCC suspension and liquidation procedures, see OCC Rules 1101–1110.

[29] 11 U.S.C. 362(b)(6) (1988).

[30] In the situation where an Affiliated Clearing Member becomes insolvent, the Non-Proprietary Cross-Margin Account assets will be set-off against related liabilities in the account. If the insolvent Affiliated Clearing Member is a broker-dealer, OCC would perform the appropriate set-off, if the Clearing Member were an FCM, CME would perform the set-off.

[31] 11 U.S.C. 742 (1988). 15 U.S.C. 78aaa–78lll (1988).

[32] 11 U.S.C. 742 (1988).

[33] Subchapter IV, chapter seven, of the Bankruptcy Code, 11 U.S.C. 761–766 (1988).

[34] As explained below, the Commission, the CFTC, and SIPC, have reviewed and concur in OCC's and CME's analyses of what will happen in the event of a Clearing Member default or insolvency and the legal basis for these conclusions.

15 U.S.C. 78fff–1(b) (1988) states in part:

Continued

SIPC does not exercise its power to seek appointment of a trustee and SIPA does not apply to the liquidation, it is the intended result that Market Professional claims to assets in the Non-Proprietary Cross-Margin Account be determined in accordance with the Bankruptcy Code's commodity broker liquidation requirements [35] and applicable CFTC regulations.

Generally, applicable sections of the Bankruptcy Code and CFTC regulations [36] provide for the trustee to distribute *prorata* customer property [37] among customers [38] according to account class and generally give priority to customer claims over all others, except those dealing with the administration of the bankrupt estate.[39] Also, assuming the trustee does not transfer customer accounts to another firm and determines to liquidate customer accounts, the trustee will distribute customer property and estate assets to the claimants. Of course, to the extent customer property is insufficient to satisfy customer claims, the trustee will use estate assets and, if necessary, proceeds from the Non-Proprietary Cross-Margin Account to pay customer claims before paying a distribution to the Market Professionals claiming cross-margin assets.

III. Comments

The Commission received two comment letters from OCC Clearing Members on OCC's proposal.[40] In general, the commentators expressed support for the proposal. One comment letter emphasized that OCC's proposal would assist the responding firm in managing its cash flow by lowering the firm's initial margin requirements for neutral or hedged positions. The other comment letter stated that the proposal would benefit Market Professionals by reducing their liquidity concerns during periods of market stress.

IV. Discussion

After the October 1987 market break, a number of reports were written by market regulators, special committees, and others in an effort to provide a comprehensive view of the events and activities surrounding the market break. Perhaps the single most significant conclusion, common to most if not all the reports, was the recognition that ostensibly different markets that trade economically equivalent products operate as a single market.[41] The Brady Report Stated:

> Analysis of the market behavior during the crucial days in mid-October makes clear an important conclusion. From an economic viewpoint, what have been traditionally seen as separate markets—the markets for stocks, stock index futures, and stock options—are in fact one market. Under ordinary circumstances these marketplaces move sympathetically, linked by a number of forces.[42]

Although the stock, stock-index options, and stock index futures markets are integrally related, the clearance and settlement mechanisms associated with these markets are separate and distinct. For example, all stock transactions are cleared through three interfaced clearing organizations. The National Securities Clearing Corporation clears approximately 95% of all stock transactions. Clearing facilities for exchange-traded options are centralized at OCC. Although the vast majority of the volume of stock index futures is traded and cleared at CME, stock index futures also are traded and cleared at three other futures exchanges and are cleared through those futures exchanges' related clearing entities.

A consequence of the fragmentation in clearing and settlement systems is that no single clearing entity has an overview of the total market exposure of Clearing Members who participate in two or more markets simultaneously.[43] While an overall position may be relatively neutral in terms of profit or loss, a market participant might be required to meet immediately additional margin calls resulting from losses in one market even though it has offsetting profits in another. This segmented system affects banks as well by increasing liquidity demands of customers who cannot use profits in one market as collateral for transactions in another. As the Brady Report noted:

> In the current system, margin flows are based on intramarket positions, and the timing of margin flows differs across clearinghouses. For the sort of intermarket transactions which are the mainstay of these markets, funds must be shuttled from clearinghouse to clearinghouse in the margin settlement process. This process creates imbalances in financing needs and increases demand for bank credit.[44]

Accordingly, the Brady Report recommended that cross-margining be allowed because market participants with an investment in futures should be allowed to receive credit for a hedged investment in stocks or options.[45] The President's Working Group on Financial Markets came to the same conclusion and recommended that the securities, futures, and banking industries participate in pursuing initiatives, such as cross-margining, to reduce cash flow stress during periods of market volatility.[46]

In the Proprietary Cross-Margin Order, the Commission set forth its reasons for approving the OCC/CME Proprietary Cross-Margin Program.[47] Those reasons included: (1) Increased safety and reliability of clearance and settlement systems for commodity clearing organizations by providing the

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To the extent consistent with the provisions of this Act or as otherwise ordered by the court, a trustee shall be subject to the same duties as a trustee in a case under chapter 7 of title 11 of the United States Code, including, if the debtor is a commodity broker, as defined under section 101 of such title, the duties specified in subchapter IV of such chapter 7.

At this time, the Commission is not aware of any such inconsistencies between the provisions of SIPA and the Bankruptcy Code. Moreover, the Commission understands that the Market Transactions Advisory Committee (See Securities Exchange Act Release No. 29801 (October 9, 1991), 56 FR 52080) will be asked to explore if any inconsistencies exist and, if so, how they should be addressed.

[35] Subchapter IV, chapter seven, of the Bankruptcy Code, 11 U.S.C. 761–766 (1988).

[36] 11 U.S.C. 761–766 (1988) and 17 CFR 190.01–.10 (1991).

[37] The Bankruptcy Code defines customer property to include "cash, a security, or other property, or proceeds of such cash, security or property, received, acquired, or held by or for the account of the [commodity broker], from or for the account of a customer * * *." 11 U.S.C. 761(10) (1988).

[38] The Bankruptcy Code defines a "customer" of an insolvent commodity broker to include an:

(i) Entity for or with whom the [commodity broker] deals and that holds a claim against the [commodity broker] on account of a commodity contract made, received, acquired, or held by or through the [commodity broker] in the ordinary course of the [commodity broker's] business as a [commodity broker] from or for the commodity futures account of such entity; or

(ii) Entity that holds a claim against the [commodity broker] arising out of:

(I) The making, liquidation, or change in the value of a commodity contract of a kind specified in clause (i) of this subparagraph;

(II) a deposit or payment of cash, a security, or other property with the debtor for the purpose of making or margining such a commodity contract; or

(III) the making or taking of delivery on such a commodity contract. 11 U.S.C. 769(9) (1988).

[39] 11 U.S.C. 766(h) (1988).

[40] Letter from Douglas J. Engmann, President, Sage Clearing, to Secretary, Commission (April 14, 1990) and letter from Carl H. Hewitt, General Counsel, Spear, Leeds & Kellogg, to Secretary, Commission (May 4, 1990).

[41] U.S. Securities and Exchange Commission, Division of Market Regulation, The October 1987 Market Break ("SEC Report") (February 1988), at 3–1 to 3–9; Report of the Presidential Task Force on Market Mechanisms ("Brady Report") (January 1988), at 55–57; and CFTC, Division of Economic Analysis and Division of Trading and Markets, Final Report on Stock Index Futures and Cash Market Activity During October 1987 (January 1988), at 138.

[42] Brady Report at 55.

[43] Although 48 of OCC's 143 Clearing Members are registered as both a broker-dealer and an FCM, most of the 48 conduct little if any futures trading. Generally these dually registered firms conduct their futures transactions through an affiliate.

[44] Brady Report at 64.

[45] Brady Report at 65–66.

[46] Interim Report of the Working Group on Financial Markets, at 6 (May 1988).

[47] Proprietary Cross-Margin Order, *supra* note [5].

CME with a perfected security interest in OCC options in cross-margin accounts;[48] (2) the possibility of significant reductions in Clearing Members' cash flow requirements during routine and volatile markets; (3) the adoption of adequate OCC/CME procedures to address the risk of price divergence between the options and futures legs of intermarket hedges; and (4) the existence of reasonable precautions to help ensure both OCC and CME have perfected interests in Clearing Members' accounts, deposits, and assets in OCC and CME possession or control. The main difference between the Proprietary Cross-Margin Program and the Non-Proprietary Cross-Margin Program being approved today is that under the Non-Proprietary Cross-Margin Program the Clearing Members receive margin benefits for positions that are not the Clearing Members' own positions. Instead, each participating Clearing Member receives the margin benefits of the hedged[49] positions resulting from the combined positions of Market Professionals whose positions the Clearing Member carries in the Non-Proprietary Cross-Margining Account. From the Clearing Member's perspective, the proposal might be described as a netting program with the Clearing Member netting the combined exposures of all Market Professionals it carries, although it is equally appropriate to describe the arrangement as a cross-margining program for the Clearing Member because the Clearing Member is liable to the Clearing organization, as principal, for these positions.[50] From the perspective of the Market Professional, the program can be characterized as a cross-margining program because the Market Professional's required margin is based on the combined positions of that Market Professional.

Support for cross-margining systems has been substantial. For example, the Brady Report noted that the absence of an effective cross-margining system for futures and securities options markets contributed to payment strains in October 1987. Nevertheless, other considerations must be addressed before the Commission can approve expansion of cross-margin facilities for Market Professionals whose accounts are maintained by OCC and CME Clearing Members. These include implications for Clearing Member and Market Professional margin deposit and net capital requirements and distribution of assets in the event of a Clearing Member or Market Participant liquidation.

Under the Non-Proprietary Cross-Margin Program, each participating Clearing Member's OCC and CME margin requirement will be based on the combination of the Market Professionals' positions that the Clearing Member carries and will be decreased by any resulting related or hedged positions. Thus, the proposal will likely contribute to a reduction in Clearing Member margin requirements at OCC and CME where the obligations inherent in one or more futures contracts held for electing Market Professionals are offset by the rights inherent in one or more option contracts in the same cross-margin account at the clearing organization.

For example,[51] assume there are two Affiliated Clearing Members, CM1 that clears through OCC and CM2 that clears through CME. Assume further that there are three Market Professionals, MP1, a registered broker-dealer, MP2, an FCM and not a registered broker-dealer, and MP3, a registered broker-dealer. Each of MP1, MP2, and MP3, respectively, clears its options transactions through CM1 and its futures transactions through CM2. MP1 holds short five call options on the Standard and Poor's 500 Index ("SPX"). MP2 holds long one future on the Standard and Poor's 500 Index ("SPZ"). MP3 holds short five SPX call options and holds long one SPZ future. Also assume that short SPX call options are deep-in-the-money. Under the current margin system, for MP1's short SPX call options, CM1 would pay to OCC premium margin of $10,000 (5 contracts x $2,000/contract) plus risk margin of $9,000 (5 contracts x 1,800/contract) for a total of $19,000. For MP2's SPZ future, CM2 would pay to CME risk margin of $9,000. For MP3's short SPX call option, CM1 would pay to OCC premium margin of $10,000 (5 contracts x $2,000/contract) plus risk margin of $9,000 (5 contracts x $1,800/contract), and for MP3's long SPZ future, CM2 would pay to CME risk margin of $9,000. Under the current system, CM1's total payments to OCC would be $20,000 premium and $18,000 risk margin, and CM2's total payments to CME would be $18,000 risk margin. Together, CM1 and CM2 would make total payments of $56,000 for premiums ($20,000) and risk margins ($36,000) to OCC and CME.

Under the Non-Proprietary Cross-Margin Program, the Clearing Members, provided they elect to participate in, qualify for, and fulfill all the requirements of the Non-Proprietary Cross-Margin Program, would be required to pay approximately $23,000 (a reduction of $33,000) on account of contracts held for MP1, MP2, and MP3. CM1 and CM2 would have one joint cross-margin account into which all margin would be paid. The Clearing Members would deposit into the account $20,000 premium margin for the short SPX call options ($10,000 for MP1's five short SPX contracts and $10,000 for MP3's five short SPC call options and $7,500 for MP3's short SPX call options). The risk margin on the long SPZ futures would remain the same, and the Clearing Members would be required to deposit into the account risk margin of $18,000 ($9,000 for MP2's long SPZ future and $9,000 for MP3's long SPZ future). Under the Non-Proprietary Cross-Margin Program, however, the Clearing Members would receive a $15,000 risk margin reduction because the liquidation costs of the SPZ futures offsets the liquidation cost of the short SPX option contracts. This credit totals $15,000 ($7,500 for MP1's short call options), so the Clearing Members would be required to deposit only $3,000 ($18,000–$15,000) into the joint cross-margin account. Together, CM1 and CM2 would make a total deposit into the cross-margin account of $23,000 ($20,000 for premiums and $3,000 for risk margin).

OCC and CME collect margin from their Clearing Members only. OCC and CME Clearing Members are responsible for collecting margin from Market

[48] It was the practice for many commodities clearing organizations to reduce their Clearing Members' margin requirements on the basis of options positions at OCC even though the commodities clearing organizations had no interests in the positions and would not realize any benefits from those positions in the event of a Clearing Member default.

[49] In this Order, the terms hedge or offset refer to futures and options positions of one or more Market Professionals held by a Clearing Member in a Non-Proprietary Cross-Margin Account that correlate so that possible losses in one instrument can be reduced by possible gains in another instrument (*e.g.*, a long futures contract on the Standard and Poor's 500 Index with a long put option contract on the Standard and Poor's 500 Index). Use of the terms hedge or offset in this Order should not be read as necessarily defining or interpreting hedge or offset as those terms are defined in the Act, CEA, Bankruptcy Code, or any of the rules and regulations thereunder.

[50] As discussed below, a Clearing Member is liable to the clearing organization for all positions the Clearing Member carries on the clearing organization's books whether those positions are proprietary or non-proprietary (*i.e.*, customer positions). If a clearing organization issues a margin call or a premium is due for a contract, the Clearing Member must meet that payment obligation when due even if the Clearing Member's customer has not yet paid. (Ordinarily, 100 percent of a Market Professional's positions carried by its Clearing Member are subject to OCC lien. OCC By-Laws, art. VI, Section 3.)

[51] All of the examples below are approximations. Actual figures may vary upon implementation of the Non-Proprietary Cross-Margin Program to the respective markets and the respective Clearing Members.

Professionals. The margin level requirements for Market Professionals are set by the exchanges, subject to Commission and Federal Reserve Board oversight for securities and securities options and, in limited circumstances, by the CFTC for futures and futures options positions.[52]

In the above example, because MP1 is a market-maker MP1 pays good faith margin [53] to CM1 on five short SPX call options. CM1 determines the amount of margin it requires from MP1 on the basis of various factors, including, among other things, CM1's appraisal of the assets in MP1's account.[54] Because the amount of margin CM1 must collect from MP1 is good faith margin, CM1 may finance MP1's securities positions up to 100 percent of the position's market value. It is not clear to what extent, if any, CM1's lower margin requirements resulting from the Non-Proprietary Cross-Margin Program (because of MP3's offsetting future position at CM2) will be passed from CM1 through to MP1. If CM1's lower margin requirements are passed through, there is the danger that in the event of MP1's default on its obligations, CM1 would not have collected enough margin to cover any shortfall in the subsequent liquidation of MP1.

MP2's margin requirement with CM2 is for one long SPZ future. The minimum margin for such a position is set by CME rules and is based upon the overall risk, as assessed by the CME, of MP2's position. Currently, the amount of margin MP2 would be required to deposit with CM2 for one long SPZ future is $9,000 if MP2 is a futures exchange member or $22,000 if MP2 is any other customer. This $9,000 (or $22,000) minimum margin amount will not change by virtue of the Non-Proprietary Cross-Margin Program even if CM2's margin requirements are reduced because a CME Clearing Member may not use one Market Professional's position to reduce the margin requirements of another Market Professional.

MP3's margin requirement with CM2 is for one long SPZ future, and MP3's margin requirement with CM1 is for five short SPX call options. Because MP3 is a market-maker, CM1 must collect "good faith" margin without regard to MP3's futures positions.[55] Furthermore, because CME rules currently allow CM2 to take account of off-setting positions in determining margin requirements and because MP3 has five short SPX call options as an offset or hedge in an account with CM1, CM2 can reduce MP3's margin requirement below the $9,000 CM2 would otherwise be required to collect even though CM2 has no security interest in the options held by CM1 for MP3.[56]

Under the Non-Proprietary Cross-Margin Program, MP3's margin requirement will be based on the combination of MP3's five short SPX call options and one long SPZ future. In this case, MP3 likely will have to pay approximately $2,920 in margin to CM1 and CM2.[57]

Under the Commission's uniform net capital rule,[58] a clearing firm must calculate for each market-maker (*i.e.*, Market Professional) the account equity [59] in the market-maker's account and the haircuts on the positions carried in market-maker's account. If there is a negative equity in the market-maker's account, the market-maker may not continue trading and the clearing firm may not extend further credit to the market-maker, must call for additional equity, and ultimately must liquidate the positions in the account to eliminate the deficit.[60] Assuming there is positive equity in the market-maker's account, a clearing firm must reduce its net capital to the extent that the haircuts relating the market-maker's account exceed the equity in the market-maker's account.[61] The net capital rule also imposes limits on the aggregate volume of market-maker business a clearing firm may carry and clear.[62]

Generally, in calculating the equity in a market-maker's account to determine whether a market-maker may conduct trading (*i.e.*, whether the equity in the market-maker's account is positive or negative), a Joint Clearing Member may consider the liquidating equity of the market-maker's securities options positions and not the market-maker's futures liquidating equity. However, in certain situations, a Joint Clearing Member may receive beneficial treatment under the net capital rule for certain options positions carried in a market-maker's account that are offset by certain futures positions of the same market-maker.[63] In determining if it

[52] Exchange rules setting levels of margin are not subject to CFTC review. (CEA section 5a(12), 7 U.S.C. 7a(12) (1988)). In certain emergencies, however, the CFTC may impose minimum margin levels. (CEA section 8a(9), 7 U.S.C. 12a(9) (1988)). In addition, exchange rules establishing the forms in which margin may be deposited are subject to CFTC review. (CEA section 5a(12), 7 U.S.C. 7a(12) (1988)).

[53] Regulation T, issued by the Board of Governors of the Federal Reserve System, governs the extension of credit by brokers and dealers. Section 220.12(b)(3) of Regulation T (12 CFR 220.12(b)(3) (1991)) states, "[t]he required margin for a specialists's transaction shall be: good faith margin."

Regulation T defines good faith margin as "the amount of margin which a creditor, exercising sound credit judgment, would customarily require for a specified security position and which is established without regard to the customer's other assets or securities positions held in connection with unrelated transactions." 12 CFR 220.2(k) (1991). "Good faith loan value should reflect the creditor's [Clearing Member's] business judgment based on arms's length dealing with the borrower [Market Professional], the creditor's general lending practice, and the nature of the collateral." Board Rulings and Staff Opinions Interpreting Regulation T, Loan Value, Good Faith, Fed. Res. Reg. Serv. 5-644 (August 30, 1974)

[54] Section 7(C)(2) of the Act makes it "unlawful for any member of a national securities exchange or any broker-dealer, directly or indirectly, to extend credit to or for any customer without collateral or on any collateral other than securities * * *." 15 U.S.C. 78G(C)(2) (1988). CM1, therefore, cannot extend credit to MP1, based upon the future in MP2's account.

[55] This is, in effect, the same margin CM1 was required to collect from MP1.

[56] Although as stated above, CME currently permits CM2 to grant a reduced margin requirement to MP3 for its offsetting options positions, CM2 has no security interest in MP3's options positions held at CM1. Under the Non-Proprietary Cross-Margin Program, both CM1 and CM2 will have a lien on all assets held in the Non-Proprietary Cross-Margin Account. Therefore, under the Non-Proprietary Cross-Margin Program, the rights and obligations of CM1 and CM2 will be more predictable in the event of MP3's bankruptcy. Telephone conversation between Lori R. Burns, Assistant General Counsel, CME, and Jack Drogin, Attorney Adviser, Division, Commission (October 21, 1991).

[57] Since the relative differences in option strike prices, option cash prices, past market volatility, market rates of interest, and futures and options expiration dates all affect the margin required under the Non-Proprietary Cross-Margin Program, the actual required margin will vary from $0 to $9,000. Based on conversations with CME and OCC, the Commission understands that the minimum margin in this case will likely be approximately $2,920. Telephone conversations between Lori R. Burns, Assistant General Counsel, CME and Jack Drogin, Attorney Adviser, Division, Commission (August 5-9, 1991). Telephone conversations between James C. Yong, Assistant Vice President and Deputy General Counsel, OCC, and Jack Drogin, Attorney Adviser, Division, Commission (August 5-9, 1991).

[58] Rule 15c3-1 (17 CFR 240.15c3-1 (1991)). Generally, net capital is computed by adding to net worth, as computed under generally accepted accounting principles, certain liabilities that are subordinated to the claims of customers and by deducting from net worth certain assets not readily convertible into cash and certain percentages of the market values of all proprietary positions. These percentage deductions, referred to as "haircuts," are intended to provide for the market and credit risk inherent in a broker-dealer's securities positions. SEC Report at p. 5-2.

[59] For purposes of the uniform net capital rule, equity is computed by marking all long and short securities positions in the account to their respective current market value, adding the credit balance (deducting in the case of a debit balance) in the account, and adding the market value of long positions (deducting in the case of short positions) in the account. 17 CFR 240.15c3-1(c)(2)(x)(B)(2) (1991).

[60] 17 CFR 240.15c3-1(c)(2)(x)(G) (1991).

[61] 17 CFR 240.15c3-1(c)(2)(x)(F) (1991). See also no-action letter from Lee A. Pickard, Director, Division, Commission, to Joseph W. Sullivan, President, Chicago Board Options Exchange, Inc. ("CBOE") (April 8, 1977).

[62] 17 CFR 240.15c3-1(C)(2)(x)(B)(1) (1991).

[63] The beneficial net capital treatment is limited to situations where the clearing firm carries both the

Continued

must take a net capital deduction relating to a market-maker's account (*i.e.*, determining if the haircuts on a market-maker's positions exceed the market-maker's equity), a Joint Clearing Member may include certain futures positions of the market-maker in calculating the market-maker's account equity.[64]

One important consideration is the risk that cross-margined futures and options positions will not be maintained, thereby increasing the risk of financial strains on the Clearing Member carrying the account. The OCC/CME proposal does not provide a mechanism to ensure that Market Professionals unwind combined futures and options positions simultaneously, and the Clearing Member ordinarily has no control over the establishment or liquidation of these positions.[65] Thus, it is possible that a Market Professional could affect the Clearing Member adversely by liquidating one side of the combined position.

In the event one side of a combined position is closed out, OCC/CME will require additional margin from the Clearing Member based on the remaining position. Assuming the Clearing Member's existing margin deposits together with the proceeds from the closed position are inadequate to cover this additional margin requirement, the Clearing Member could be required to deposit additional margin with OCC/CME. During volatile markets, this could create additional stress on Clearing Member resources and on the national payment systems that must be used to transfer funds between the Clearing Member and OCC/CME. Experience indicates that one side of a combined position (*e.g.*, the stock index future side of a stock index future—stock index option combined position) might be left at a time when the market for that position may be closed but the market for the components of the underlying index (*e.g.*, S&P 100) continues to trade and prices and index values move adversely to the remaining position. Because Clearing Members are only required to collect good faith margin from Market Professionals,[66] they may not have the funds necessary to satisfy the severe cash demands that could arise from closing out one side of a combined position and the resulting increased margin requirements. This could occur whether the close out of one side was unintentional (*i.e.*, where one Market Professional's options positions are being used to offset another Market Professional's futures positions at the Clearing Member level for purposes of determining the Clearing Member's margin deposit requirements to OCC or CME) or intentional (*i.e.*, where the same Market Professional has both the options and the futures positions).[67]

The intentional close out of one side of a combined or hedged position is a risk that already exists in the OCC/CME Proprietary Cross-Margin Program. Generally, this occurs shortly prior to the expiration of options and futures positions where the time value of positions are smallest and options are often already deep-in-the-money. To address this risk in situations where the cross-margined position consists of options and futures with different expiration dates, OCC has represented to the Commission that it routinely breaks these combined positions into their component parts two days before the expiration date of the side closest to expiration (*i.e.*, futures or options positions). OCC then computes margin based on each of the positions.[68]

OCC and CME have instituted a series of safeguards to reduce the risk of exposure to OCC and CME because of the intentional and unintentional close out of one side of a hedged or combined position. These safeguards provide a basis for temporary approval of the proposed Non-Proprietary Cross-Margining Program.

OCC and CME have established minimum membership financial qualifications. OCC has recently increased minimum capital requirements for its members and significantly increased its capital requirements for members that manage the accounts of other Clearing Members.[69] In addition to reviewing routine, periodic financial reports from Clearing Members, OCC participates with other clearing agencies in the Securities Clearing Group ("SCG") to share risk management information about common Clearing Members.[70] Furthermore, under the terms of the Agreement, as amended, OCC will be advised of any information received by CME which causes CME significant concerns over the financial or operational capabilities of a Clearing Member. Recently, OCC also has entered into a similar cross-margining agreement with the Board of Trade Clearing Corporation ("BOTCC"). Under that agreement, both OCC and BOTCC are required to provide the other with certain relevant information regarding the financial or operational status of Clearing Members using the cross-margining program.[71]

Second, OCC continuously monitors the financial condition of its Clearing Members and the potential financial exposure from the account positions in comparison to its Clearing Members' available net capital in the event the underlying asset values fluctuate substantially.[72] OCC uses two computer systems, the Theoretical Intermarket Margin System ("TIMS") and the Concentration Monitoring System ("ConMon"), to monitor Clearing Members' exposure to market risk and to set margin requirements accordingly. OCC Clearing Members are requested to

securities options positions and the futures positions of a market-maker. Therefore, Affiliated Clearing Members, although allowed to participate in the OCC/CME Non-Proprietary Cross Margin Program, may not take advantage of the current or requested beneficial net capital treatment. Letter from Michael Macchiaroli, Assistant Director, Office of Compliance and Financial Responsibility, Division, Commission, to New York Stock Exchange, Inc. (December 3, 1984). Letter from Lee A. Pickard, Director, Division, Commission, to Joseph W. Sullivan, President, CBOE (April 8, 1977).

[64] Letter from Michael Macchiaroli, Assistant Director, Division, Commission, to Donald van Weezel, Managing Director Regulatory Affairs, New York Stock Exchange, Inc., to Mary Bender, Assistant Vice President, Department of Financial Compliance, CBOE, and to James McNeil, Assistant Vice President, American Stock Exchange (December 3, 1984).

[65] The Clearing Member might exercise control over the positions in the event the Market Professional defaulted on its obligations to the Clearing Member (*e.g.*, if the Market Professional failed to cure a deficit in his account).

[66] Regulation T, *supra* note 53.

[67] The intentional close out of one side of combined or hedged positions usually results from a Market Professional's decision to liquidate the two sides at different times either because the Market Professional hopes to increase the profit on the position or because liquidation of both positions simultaneously cannot be arranged. In both cases, the Market Professional, and in turn the Clearing Member, can be exposed to significant financial risk.

[68] For example, an options spread position which is due to expire on September 30 may be hedged with an options or futures position due to expire on November 30. On September 28, OCC will break the spread and move the positions into separate product groups. Because no cross-margin treatment will be afforded the positions, the Clearing Member's margin requirement will be increased.

[69] See Securities Exchange Act Release No. 26840 (May 19, 1989), 54 FR 23005.

[70] See Securities Exchange Act Release No. 27044 (July 18, 1989), 54 FR 30963 (order approving formation of SCG and authorizing information sharing by participants). The SCG is an association of clearing agencies that was formed for the purpose of engaging in coordinated action to address common issues of the clearance and settlement system. A key goal of the SCG is the development of procedures that will help assess the operational and financial condition of common participants. The Securities Clearing Group maintains a common data base regarding common Clearing Member settlement and daily financial exposure.

[71] Securities Exchange Act Release No. 29883 (October 31, 1991), 56 FR 56680.

[72] OCC's member monitoring procedures were most recently discussed in the Division's report on the events surrounding the market decline on October 13 and 16, 1989. See Commission, Division, Market Analysis of October 13 and 16, 1989, 137–142 (December 1990).

report all option and futures positions, as well as the account equity, held in Clearing Members' various accounts. Using this information, TIMS uses advanced portfolio theory to recognize economically and statistically reasonable hedges among positions. Using a sophisticated options pricing model, in conjunction with the ability continuously to update data on the level of interest rates, days to expiration, dividend streams, and market implied volatility, TIMS projects the liquidation cost of each portfolio given assumed changes in the price of the underlying securities. OCC continuously monitors intraday price changes and is empowered to issue intraday margin calls if necessary.[73] TIMS is supplemented by ConMon, which provides a comparison of the capital and net worth of each OCC Clearing Member to the market risk associated with the Clearing Member's positions. ConMon performs a sensitivity analysis of that risk over a wide band of potential volatility and price assumptions. Results are compared to the Clearing Member's net capital. Additionally, ConMon measures the degree of diversification within a Clearing Member's account, as well as the size of a position relative to the total volume in that market.

Third, OCC also uses these systems to evaluate the risks posed by individual market-makers to a Clearing Member even where the Clearing Member itself does not pose any risk to OCC. Thus, if an individual market-maker's positions have been assessed as presenting a risk, OCC staff will investigate the circumstances and, if necessary, may cause the Clearing Member to take certain actions to remedy the matter.

OCC has recently developed a risk management system ("RMS") which is based on the same principals inherent in TIMS and ConMon. RMS has been developed to help its users evaluate positions across markets in the same manner that OCC manages its risk from Clearing Members. RMS has been made available to Clearing Members and the Designated Examining Authorities ("DEAs"). Certain DEAs mandate that market-makers entering a transaction on its floor provide OCC with the relevant information needed to operate RMS.[74] The DEAs will use RMS as a supplement to their financial responsibility compliance program.

Fourth, OCC has modified its rules to establish a minimum risk margin component in the calculation of Clearing Member margin requirements.[75] As noted below, this would apply to both proprietary and Non-Proprietary Cross-Margin Accounts as well as other OCC accounts. Because the modification will establish a Minimum margin requirement for positions that combine long and short contracts, hedged positions will require a minimum margin deposit. Thus, the larger the number of combined long and short positions in a cross-margin account (proprietary or nonproprietary), the greater the minimum margin OCC will require and the less financial risk to OCC if any combined positions are closed out intentionally or unintentionally.

The Commission is satisfied that OCC and CME have taken appropriate steps to provide explicit statements concerning the expectations of clearing members and market professionals about their rights and obligations in the event of a Clearing Member default or insolvency. The Commission, SIPC, and CFTC have reviewed and concur in OCC's and CME's analysis, as outlined above, of what will happen in the event of a clearing member default or insolvency and the legal basis for those conclusions. These expected results are outlined in substantial detail in this Order and the CFTC Order.

The Commission believes the Non-Proprietary Cross-Margining Program will not result in a burden on competition not necessary or appropriate in furtherance of the purposes of the Act.[76] As the reports and studies mentioned above have suggested,[77] the interrelationships between the financial markets and the need for a system of margining which reflects the true of investments [78] makes cross-margining of futures and options positions highly worthwhile. Since the Non-Proprietary Cross-Margining Program being temporarily approved by this Order both helps to further such a system of margining and is open to all OCC and CME members who choose to participate, the Commission believes the Non-Proprietary Cross-Margining Program is fully consistent with section 17A of the Act.

The Commission believes that the proposal will enhance Clearing Member and systemic liquidity on a routine basis and, potentially, during periods of market stress. During routine markets, Clearing Members will benefit from lower initial margin deposits which both will assist Clearing Members in managing their cash flow and will increase the available cash to be used for other purposes. During times of market stress or price volatility, the lower initial margin deposits potentially could be important for maintaining Clearing Member liquidity. For example, during the market volatility experienced on October 13, and 16, 1989, the two firms participating in the Proprietary Cross-Margin Program paid $164 million less initial margin for their cross-margined positions than they would have been required to pay otherwise.[79] The Commission believes the proposed Non-Proprietary Cross-Margin Program will have similar results.

In sum, the Commission believes the OCC proposal is consistent wit the Act and, in particular, with section 17A of the Act. One of the purposes of section 17A is to enhance the safe and efficient operation of the clearance and settlement system. In connection with this, the Commission believes OCC's proposal will enable Market Professionals to reduce the risks associated with their market-making activities. Additionally, the proposal could add liquidity and depth to the markets and could enhance the safety of

[73] OCC Rule 609.

CME performs similar intraday price reviews and has similar authority to collect intraday margin deposits. CME Rules 824 and 828.

[74] See, *e.g.*, CBOE Regulatory Circular RG91-22 (February 15, 1991).

[75] See File Nos. SR-OCC-91-18 and SR-91-01, Securities Exchange Act Release No. 29990 (November 26, 1991), 56 FR ______. Under those proposals, OCC and ICC will each calculate the minimum risk margin ("additional margin") component for each product group in each account as follows: (1) For each "net" short position in securities options, IPs, or commodities options in the product group and for each net long or short position in futures in the product group, the number of contracts in the net position would be multiplied by an eighth of a point, and that result would be multiplied by the applicable unit of trading, index multiplier, or multiplier; (2) for each net long securities option, IP, or commodities option position in the product group, the number of contracts in the net long position would be multiplied by the lesser of an eighth of a point or the value of the premium margin credit for the net long position, and that result would be multiplied by the applicable unit of trading, index multiplier, or multiplier; (3) the values determined pursuant to steps (1) and (2) for all net short and all net long positions would be added together; and (4) if the value determined for a product group pursuant to step (3) is greater than the amount calculated by the current TIMS additional margin calculation, the value determined pursuant to step (3) would be the additional margin amount for the product group.

[76] Section 17A(b) (3) (I) of the Act, 15 U.S.C. 78q-1(b) ((3) (I), preclude the rules of a clearing agency from imposing "any burden on competition not necessary or appropriate in furtherance of the purpose of this title."

[77] See supra note 41.

[78] See e.g., Timothy F. Hinkes, Cross-Margining and Futures-Style Margining: The Facts, Commodities Law Letter, Volume VIII No. 9 & 10 (November/December 1988).

[79] Commission, Division, Market Analysis of October 13 and 16, 1989, at 146 (December 1990).

the clearance and settlement system by decreasing the potential for financial gridlock and by reducing the likelihood of Clearing Member default. In order to allow examination of the results of the Non-Proprietary Cross-Margin Program, the Commission believes it is appropriate to grant temporary approval at this time. The Commission therefore is approving OCC's request on a temporary basis through November 30, 1993.

V. Conclusion

For the reasons stated above, the Commission finds that the proposed rule change is consistent with sections 7 and 17A of the Act.

It is therefore Ordered, pursuant to section 19(b)(2) of the Act,[80] that the File No. SR-OCC-90-01 be, and hereby is, approved on a temporary basis through November 30, 1993.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[81]

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 91-28932 Filed 12-2-91; 8:45 am]

BILLING CODE 8010-01-M

Issuer Delisting: Application To Withdraw From Listing and Registration; Burlington Holdings, Inc., Series B Junior Subordinate Discount Debentures Due 2003 (File No. 1-9704)

November 26, 1991.

Burlington Holdings, Inc. ("BHI" or "Company") has filed an application with the Securities and Exchange Commission ("Commission") pursuant to section 12(d) of the Securities Exchange Act of 1934 and Rule 12d2-2(d) promulgated thereunder to withdraw the above specified security from listing and registration on the Pacific Stock Exchange, Inc. ("PSE").

The reasons alleged in the application for withdrawing this security from listing and registration include the following:

According to the Company, the security referred to above was listed on the PSE in 1987 in order to facilitate compliance by BHI with certain state regulatory requirements in connection with its original issuance. The Company states that these objectives were met at the time of original issuance and are no longer relevant.

In addition, to the knowledge of BHI, trading volume in the debt securities referred to above is very small. In the opinion of BHI, the over-the-counter market appears to be adequately serving the existing needs of buyers and sellers and continued listing on the PSE will not provide any material benefit to buyers and sellers.

Also, BHI appears to meet at least one of the PSE's delisting standards since it does not have a class of equity securities held by 500 or more persons.

Finally, BHI would prefer to avoid the expense associated with continued listing on the PSE.

Any interested person may, on or before December 18, 1991, submit by letter to the Secretary of the Commission, 450 Fifth Street, NW., Washington, DC 20549, facts bearing upon whether the application has been made in accordance with the rules of the Exchanges and what terms, if any, should be imposed by the Commission for the protection of investors. The Commission, based on the information submitted to it, will issue an order granting the application after the date mentioned above, unless the Commission determines to order a hearing on the matter.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.

Jonathan G. Katz,

Secretary.

[FR Doc. 91-28929 Filed 12-2-91; 8:45 am]

BILLING CODE 8010-01-M

Issuer Delisting; Application To Withdraw From Listing and Registration; Burlington Industries Capital, Inc., 16.875% Senior Discount Debentures Due 2004, Senior Floating Rate Notes Due 1999 (File No. 1-10444)

November 26, 1991.

Burlington Industries Capital, Inc. ("BICI" or "Company") has filed an application with the Securities and Exchange Commission ("Commission") pursuant to section 12(d) of the Securities Exchange Act of 1934 and Rule 12d2-2(d) promulgated thereunder to withdraw the above specified securities from listing and registration on the Pacific Stock Exchange, Inc. ("PSE").

The reasons alleged in the application for withdrawing these securities from listing and registration include the following:

According to the Company, the securities referred to above were listed on the PSE in 1989 in order to facilitate compliance by BICI with certain state regulatory requirements in connection with its originial issuance. The Company states that these objectives were met at the time of original issuance and are no longer relevant.

In addition, to the knowledge of BICI, trading volume in the debt securities referred to above is very small. In the opinion of BICI, the over-the-counter market appears to be adequately serving the existing needs of buyers and sellers and continued listing on the PSE will not provide any material benefit to buyers and sellers.

Also, BICI appears to meet at least one of the PSE's delisting standards since it does not have a class of equity securities held by 500 or more persons.

Finally, BICI would prefer to avoid the expense associated with continued listing on the PSE.

Any interested person may, on or before December 18, 1991, submit by letter to the Secretary of the Commission, 450 Fifth Street, NW., Washington, DC 20549, facts bearing upon whether the application has been made in accordance with the rules of the Exchanges and what terms, if any, should be imposed by the Commission for the protection of investors. The Commission, based on the information submitted to it, will issue an order granting the application after the date mentioned above, unless the Commission determines to order a hearing on the matter.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.

Jonathan G. Katz,

Secretary.

[FR Doc. 91-28930 Filed 12-2-91; 8:45 am]

BILLING CODE 8010-01-M

DEPARTMENT OF TRANSPORTATION

Aviation Proceedings; Agreements filed during the Week Ended November 22, 1991

The following Agreements were filed with the Department of Transportation under the provisions of 49 U.S.C. 412 and 414. Answers may be filed within 21 days of date of filing.

Docket Number: 47844.
Date filed: November 18, 1991.
Parties: Members of the International Air Transport Association.
Subject: TC3 Reso/P 0439 dated October 25, 1991. TC3 Expedited Resolutions (R-1 To R-8).
Proposed Effective Date: January 1/ January 4, 1992.

Docket Number: 47845.
Date filed: November 18, 1991.
Parties: Members of the International Air Transport Association.

[80] 15 U.S.C. 78s(b)(2) (1988).
[81] 17 CFR 200.30-3 (a)(12) (1991).

Subject: TC31 Reso/P 0905 dated October 28, 1991. Japan-Canada/ Mexico/USA Expedited Reso 002o R–1 To R–10.

Proposed Effective Date: January 1, 1992.

Docket Number: 47846.

Date filed: November 18, 1991.

Parties: Members of the International Air Transport Association.

Subject: SNATC/2062 dated November 6, 1991. USA-Europe Agreement (US-UK add-ons—Resolution 015).

Proposed Effective Date: January 1, 1992.

Docket Number: 47847.

Date filed: November 18, 1991.

Parties: Members of the International Air Transport Association.

Subject: TC12 Reso/P 1358 dated September 23, 1991. Mexico-Europe Resolutions R–1 To R–20. TC12 Reso/P 1364 dated September 27, 1991. Canada-Europe Resolutions R–21 To R–38. TC12 Reso/P 1365 dated September 27, 1991. Canada-Europe Resolutions R–39 To R–44.

Proposed Effective Date: January 1/ April 4, 1992.

Docket Number: 47850.

Date filed: November 21, 1991.

Parties: Members of the International Air Transport Association.

Subject: TC31 Reso/P 0909 dated November 8, 1991. Circle Pacific Resolutions R–1—002 R–2—073C.

Proposed Effective Date: April 1, 1992.

Docket Number: 47851.

Date filed: November 21, 1991.

Parties: Members of the International Air Transport Association.

Subject: TC Reso/P 1158 dated November 11, 1991. Middle East-Africa Expedited Resolutions R–1 To R–4.

Proposed Effective Date: January 1, 1992.

Docket Number: 47852.

Date filed: November 21, 1991.

Parties: Members of the International Air Transport Association.

Subject: Comp Mail Vote 520 (Resolution 011a) R–1. Comp Mail Vote 522 (Resolution 003y) R–2.

Proposed Effective Date: December 1, 1991.

Docket Number: 47853.

Date filed: November 21, 1991.

Parties: Members of the International Air Transport Association.

Subject: TC2 Reso/P 1148 November 7, 1991. Expedited Within Europe R–1; intended effective date: December 1, 1991. TC2 Reso/P 1149 dated November 7, 1991. Expedited Within Europe R–2 To R–3; intended effective date: January 15/ February 10, 1992. TC2 Reso/P 1150 dated November 7, 1991. Expedited Within Europe R–4 To R–6; intended effective date: February 1/February 10, 1992. TC2 Reso/P 1151 dated November 7, 1991; intended effective date: December 1, 1991 R–7; TC2 Reso/P 1152 dated November 7, 1991. Expedited Within Europe R–8 To R–9; intended effective date: January 15/February 10, 1992.

Docket Number: 47854.

Date filed: November 21, 1991.

Parties: Members of the International Air Transport Association.

Subject: Mail Vote 521 (Fares between Japan and Korea) F–1 To R–9.

Proposed Effective Date: December 2, 1991.

Docket Number: 47855.

Date filed: November 21, 1991.

Parties: Members of the International Air Transport Association.

Subject: PSC/Reso/060 dated November 7, 1991. Expedited Resolutions/Recommended Practices R–1 To R–8.

Proposed Effective Date: December 1, 1991.

Docket Number: 47856.

Date filed: November 21, 1991.

Parties: Members of the International Air Transport Association.

Subject: TC123 Reso/P 0093 dated November 15, 1991. North/Mid/South Atlantic Expedited Resos 002t (r–1) and 002u (r–2).

Proposed Effective Date: January 1, 1992.

Docket Number: 47857.

Date filed: November 21, 1991.

Parties: Members of the International Air Transport Association.

Subject: PSC/Reso/061 dated November 13, 1991. Finally Adopted Resolutions R–1 To R–58.

Proposed Effective Date: June 1, 1992.

Docket Number: 47859.

Date filed: November 22, 1991.

Parties: Members of the International Air Transport Association.

Subject: PAC/Reso/370 dated November 11, 1991. Expedited Resolutions R–1 To R–15.

Proposed Effective Date: January 1, 1992.

Phyllis T. Kaylor,

Chief, Documentary Services Division.

[FR Doc. 91–28896 Filed 12–2–91; 8:45 am]

BILLING CODE 4910–62–M

Applications for Certificates of Public Convenience and Necessity and Foreign Air Carrier Permits Filed Under Subpart Q during the Week Ended November 22, 1991

The following Applications for Certificates of Public Convenience and Necessity and Foreign Air Carrier Permits were filed under subpart Q of the Department of Transportation's Procedural Regulations (See 14 CFR 302.1701 et. seq.). The due date for Answers, Conforming Applications, or Motions to Modify Scope are set forth below for each application. Following the Answer period DOT may process the application by expedited procedures. Such procedures may consist of the adoption of a show-cause order, a tentative order, or in appropriate cases a final order without further proceedings.

Docket Number: 47843.

Date filed: November 18, 1991.

Due Date for Answers, Conforming Applications, or Motion to Modify Scope: December 16, 1991.

Description: Application of Olympic Airways, S.A., pursuant to section 402 of the Act and subpart Q of the Regulations, applies for a Foreign Air Carrier Permit to operate scheduled combination passenger and cargo service over the following routings:

A. From Greece to New York and beyond to Toronto or Montreal, Canada in both directions;

B. From Greece to coterminal points New York, Boston and Chicago in both directions;

C. From Greece via one intermediate point in Europe (to be chosen at a later date by Greece) to three points in the United States of Greece's choice.

Docket Number: 47848.

Date Filed: November 18, 1991.

Due Date for Answers, Conforming Applications, or Motion to Modify Scope: December 16, 1991.

Description: Joint Application of America West Airlines, Inc., and Northwest Airlines, Inc., pursuant to section 401(h) of the Act and subpart Q of the Regulations, requests that the Department approve the transfer to Northwest of America West's certificate for Route 584 between Honolulu, Hawaii, on the one hand, and Nagoya, Japan, on the other.

Docket Number: 47860.

Date filed: November 22, 1991.

Due Date for Answers, Conforming Applications, or Motion to Modify Scope: December 20, 1991.

Description: Joint Application of Trans World Express, Inc. and Pan Am Express, Inc., pursuant to section 401(h) of the Act and subpart Q of the

Regulations, applies for approval of the transfer to TWExpress of interstate and overseas authority currently held by PAX.

Phyllis T. Kaylor,

Chief, Documentary Services.

[FR Doc. 91-28895 Filed 12-2-91; 8:45 am]

BILLING CODE 4910-62-M

Office of the Secretary

Reports, Forms, and Recordkeeping Requirements: Submittals to OMB on November 25, 1991

AGENCY: Department of Transportation (DOT), Office of the Secretary.

ACTION: Notice.

SUMMARY: This notice lists those forms, reports, and recordkeeping requirements imposed upon the public which were transmitted by the Department of Transportation on November 25, 1991, to the Office of Management and Budget (OMB) for its approval in accordance with the requirements of the Paperwork Reduction Act of 1980 (44 U.S.C. chapter 35).

FOR FURTHER INFORMATION CONTACT: John Chandler, Annette Wilson or Susan Pickrel, Information Requirements Division, M-34, Office of the Secretary of Transportation, 400 Seventh Street, SW., Washington, DC 20590, telephone, (202) 366-4735, or Edward Clarke or Wayne Brough, Office of Management and Budget, New Executive Office Building, room 3228, Washington, DC 20503, (202) 395-7340.

SUPPLEMENTARY INFORMATION:

Background

Section 3507 of title 44 of the United States Code, as adopted by the Paperwork Reduction Act of 1980, requires that agencies prepare a notice for publication in the **Federal Register**, listing those information collection requests submitted to the Office of Management and Budget (OMB) for initial, approval, or for renewal under that Act. OMB reviews and approves agency submittals in accordance with criteria set forth in that Act. In carrying out its responsibilities, OMB also considers public comments on the proposed forms, reporting and recordkeeping requirements. OMB approval of an information collection requirement must be renewed at least once every three years

Information Availability and Comments

Copies of the DOT information collection requests submitted to OMB may be obtained from the DOT officials listed in the "For Further Information Contact" paragraph set forth above. Comments on the requests should be forwarded, as quickly as possible, directly to the OMB officials listed in the "FOR FURTHER INFORMATION CONTACT" paragraph set forth above. If you anticipate submitting substantive comments, but find that more than 10 days from the date of publication are needed to prepare them, please notify the OMB officials of your intent immediately.

Items Submitted for Review by OMB

The following information collection requests were submitted to OMB on November 25, 1991.

DOT No.: 3561.

OMB No: 2120-0021.

Administration: Federal Aviation Administration.

Title: Pilots and Flight Instructors.

Need for Information: The airman certificate and/or rating application forms and the required records/logbooks/statements required by the FAR are submitted to the FAA district offices or its representatives to determine qualifications of the application for issuance of a pilot or instructor certificate rating, or authorization.

Proposed Use of Information: The information is used to determine eligibility.

Frequency: On occasion.

Burden Estimate: 256,695 hours.

Respondents: Individuals (airmen).

Form(s): FAA Form 8710-1.

Average Burden Hours Per Respondent: 15 minutes.

DOT No.: 3562.

OMB No: 2130-0504.

Administration: Federal Railroad Administration.

Title: Special Notice for Repairs.

Need for Information: To determine if proper repairs have been made to freight cars, locomotives, or tracks that have been found unsafe and removed from service.

Proposed Use of Information: To notify the railroad in writing of an unsafe condition involving a car, a locomotive, or track.

Frequency: On occasion.

Burden Estimate: 25 hours.

Respondents: 700 Railroads.

Form(s): FRA-F-6180.8 and FRA-F-6180.8A.

Average Burden Hours Per Respondent: 5 minutes.

DOT No.: 3563.

OMB No: 2138-0040.

Administration: Research and Special Programs Administration.

Title: Report of Traffic and Capacity Statistics—The T-100 System.

Need for Information: Bilateral Negotiations, international routes, carrier fitness, and airport programs.

Proposed Use of Information: Reports are used for international negotiations, monitoring air carrier fitness, international rates, and foreign air carrier applications.

Frequency: Monthly, Quarterly.

Burden Estimate: 10,440 hours.

Respondents: U.S. and foreign air carriers.

Form(s): T-100 and T-100(f).

Average Burden Hours Per Respondent: Foreign air carriers 1 hour and 30 minutes; U.S. air carriers 10 hours.

DOT No.: 3564.

OMB No: New.

Administration: U.S. Coast Guard.

Title: Stability Design and Operational Requirements Final Rule.

Need for Information: This information collection is needed by the U.S. Coast Guard to enforce laws and regulations promoting the safety of life and property in marine transportation. These regulations apply to the following: vessels carrying liquid bulk; vessels carrying dangerous cargo; freight vessels; seagoing motor vessels; steam vessels; seagoing barges; and mobile offshore drilling units.

Proposed Use of Information: This information collection will be used by the U.S. Coast Guard to ensure that regulations regarding the submission of plans, technical information or operating instructions for vessels by the builders/designers and the logging requirements by owner/operators are met. This information and logging of stability verification will ensure the safe operation of each vessel.

Frequency: 5 year intervals and when vessels are built.

Burden Estimate: 24,482 hours.

Respondents: Builders, Designers, Owners and Operators of Vessels.

Form(s): N/A.

Average Burden Hours Per Response: 48 minutes.

DOT No: 3565.

OMB No: New.

Administration: Research and Special Programs Administration.

Title: Gas and Hazardous Liquid Pipeline Safety Program Certification/Agreement.

Need for Information: To determine state-compliance with the terms of the pipeline safety program certification/agreement.

Proposed Use of Information: To calculate state grant allocations and to prepare annual report to Congress on pipeline safety program.

Frequency: Annually.

Burden Estimate: 3,102 hours.
Respondents: State Public Service Commissions.
Form(s): Gas Pipeline Safety Program 5(a) Certification, Gas Pipeline Safety Program 5(b) Agreement, Hazardous Liquid Pipeline Safety Program 205(a) Certification, Hazardous Liquid Pipeline Safety Program 205(b) Agreement.
Average Burden Hours Per Response: Ranges from 27 to 105 hours.
DOT No: 3566.
*OMB No:*2133–0501.
Administration: Maritime Administration.
Title: Records Retention Schedule.
Need for Information: Mandatory.
Proposed Use of Information: To assure records are retained to permit proper audit of pertinent records at the conclusion of a contract.
Frequency: Quarterly, Semi-annually, Annually.
Burden Estimate: 3,914 hours.
Respondents: 38.
Form(s): None.
Average Burden Hours Per Response: 78.
DOT No: 3567.
OMB No: New.
Administration: Research and Special Programs Administration.
Title: Maps and Records of Pipeline Location and Characteristics; Notification of State Agencies; Pipeline Inventory.
Need for Information: Adequate maps and records of pipeline location and characteristics are not always available. Also, DOT lacks data on the miles of pipe in use with certain characteristics, such as type and manufacturer.
Proposed Use of Information: To identify pipelines before excavation and in emergencies; to learn the scope of pipe safety problems; to check compliance with safety requirements; and investigate-accidents.
Frequency: On occasion.
Estimated Number of Respondents: About 630 operators would be subject to the pipe inventory proposed rule. Overall about 2,500 operators of utilities for pipelines and some 81,000 master meter operators would be affected by the NPRM.
Total Estimated Burden: 2,486,862 hours attributed to pipe inventory proposal.
Form(s): The NPRM has three forms:
(1) RSPA F7100.1–2
(2) RSPA F7100.xxx
(3) RSPA F7000.xxx
Average Burden Hours Per Response: 3,947 hours.
DOT No: 3568.
OMB No: 2132–0011.
Administration: Urban Mass Transportation Administration.
Title: Environmental Assessments.
Need for Information: To comply with the National Environmental Policy Act of 1969, as amended.
Proposed Use of Information: To consider environmental consequences of proposed projects and to develop mitigation measures, if necessary.
Frequency: On occasion.
Burden Estimate: 3,720 hours.
Respondents: State or local governments.
Form(s): None.
Average Burden Hours Per Respondent: 124 hours.
DOT No: 3569.
OMB No: New.
Administration: Maritime Administration.
Title: Seamen's Claims; Administrative Action and Litigation.
Need for Information: Required to obtain or retain a benefit.
Proposed Use of Information: To assure applicant qualifies for requested benefit under the statute.
Frequency: On occasion.
Burden Estimate: 2,250 hours.
Respondents: 750.
Form(s): None.
Average Burden Hours Per Respondent: 3 hours.
DOT No.: 3570.
OMB No: 2130–0511.
Administration: Federal Railroad Administration.
Title: Designation of Qualified Persons.
Need for Information: To verify that all freight car inspections are conducted by qualified persons thus preventing unsafe movement of defective equipment.
Proposed Use of Information: To prevent the unsafe movement of defective equipment authorized by personnel unqualified to make such determinations.
Frequency: Recordkeeping.
Burden Estimate: 50 hours.
Respondents: 700 Railroads.
Form(s): None.
Average Burden Hours Per Respondent: 2 minutes.
DOT No: 3571.
OMB No: 2115–0579.
Administration: U.S. Coast Guard.
Title: Application for A Permit to Transfer Municipal or Commercial Waste.
Need for Information: This information collection is needed by the U.S. Coast Guard to ensure that vessels transporting municipal or commercial waste are in compliance with the Shore Protections Act and Coast Guard's regulations.
Proposed Use of Information: This information will be used by the U.S. Coast Guard to issue permits to owners/ operators of municipal or commercial vessels transporting waste in the coastal waters of the United States. Identification numbers will be issued and displayed on authorized vessels transporting this waste. Use of this information will also be used as a basis to revoke or deny a permit to owners/ operators found to be in violation of the Act or regulations.
Frequency: Every three years.
Burden Estimate: 366 hours.
Respondents: Owners/Operators of municipal or commercial vessels transporting waste.
Average Burden Hours Per Respondent: 50 minutes.
Form(s): None.
DOT No.: 3572.
OMB No: 2133–0005.
Administration: Maritime Administration.
Title: Uniform Financial Reporting Requirements.
Need for Information: Required to obtain or retain a benefit.
Proposed Use of Information: To assure applicant qualifies for requested benefit under the statute.
Frequency: Semi-annually, Annually.
Burden Estimate: 4,750 hours.
Respondents: 380.
Form(s): MA–172.
Average Burden Hours Per Respondent: 12 minutes.

Issued in Washington, DC on November 25, 1991.

Cynthia C. Rand,
Director of Information Resource Management.

[FR Doc 91–28894 Filed 12–2–91; 8:45 am]
BILLING CODE 4910–62–M

Federal Aviation Administration

Advisory Circular 25–17, Transport Airplane Cabin Interiors Crashworthiness Handbook

AGENCY: Federal Aviation Administration (FAA) DOT.

ACTION: Notice of issuance of advisory circular.

SUMMARY: This notice announces the issuance of Advisory Circular (AC) 25–17, Transport Airplane Cabin Interiors Crashworthiness Handbook. Advisory Circular 25–17 provides acceptable certification methods, but not necessarily the only acceptable methods, of demonstration compliance with the crashworthiness requirements of part 25 of the Federal Aviation Regulations (FAR) for transport category airplanes.

DATES: Advisory Circular 25-17 was issued by the Manager, Transport Airplane Directorate, Aircraft Certification Service, ANM-100, on July 15, 1991.

HOW TO OBTAIN COPIES: A copy of AC 25-17 may be ordered from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, or from any of the Government Printing Office bookstores located in major cities throughout the Untied States. Identify the publication as AC 25-17, Transport Airplane Cabin Interiors Crashworthiness Handbook, Stock Number 050-007-00915-1. The cost of AC 25-17 is $11.00. Send check or money order with your request, made payable to the Superintendent of Documents. Orders for mailing to foreign countries should include an additional 25 percent of the total price to cover handling. No C.O.D. orders are accepted. Issued at Renton, Washington, on November 25, 1991.

Leroy A. Keith,

Manager, Transport Airplane Directorate, Aircraft Certification Service, ANM-100.

[FR Doc. 91-28916 Filed 12-2-91; 8:45 am]

BILLING CODE 4910-13-M

Aircraft Noise Mitigation Review; Aircraft Noise Exposure in New York Metropolitan Areas; Expanded Public Hearing

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of expanded public hearing.

SUMMARY: The FAA is adding one additional phase to the public hearings held in the State of New York as part of its Aircraft Noise Mitigation Review of aircraft noise exposure in the New York metropolitan area.

DATES: The additional phase of the New York public hearings will be held on December 9, 1991, from 1-4 p.m. and 7-10 p.m. Written comments for all of the Public hearings in the New York metropolitan area must be received on or before December 31, 1991.

ADDRESSES: The additional phase of the New York public hearings will be held at the following location: College of Mount St. Vincent, South Hall, Administration Building, West 263rd Street and Riverdale Avenue, Bronx, New York 10471.

FOR FURTHER INFORMATION CONTACT: Mr. Charles R. Reavis, Program Manager, ATM-700, FAA Headquarters, 800 Independence Avenue, SW., Washington, DC 20591; telephone (202) 267-9367.

SUPPLEMENTARY INFORMATION: On October 17, 1991, the FAA issued a notice announcing its intent to conduct an Aircraft Noise Mitigation Review (ANMR) to examine aircraft noise issues and explore possible alternatives to mitigate the effects of aircraft noise in the New York metropolitan area (56 FR 55150; October 24, 1991). The review area encompasses the airspace within a 55 nautical mile radius of LaGuardia Airport, overlying the states of New York, Connecticut, and New Jersey. Legislation affirming the ANMR was enacted by Congress in section 345 of the Department of Transportation and Related Agencies Appropriations Act of 1992 (Pub. L. 102-143; October 28, 1991). The legislation specified the study area outlined by the FAA and directed the FAA to hold public hearings in the states of New York and Connecticut.

In the notice published on October 24, 1991, the FAA noted that the portions of the ANMR covering the New Jersey area would be limited to avoid unnecessary duplication of the simultaneous preparation, including public hearings, of an environmental impact statement (EIS) to study the impact over New Jersey of implementation of the Expanded East Coast Plan (EECP). Congress required preparation of the EECP EIS in section 9119(c) of the Aviation Safety and Capacity Expansion Act of 1990 (Pub. L. 101-508; November 5, 1990). Because the EECP EIS will concentrate on noise exposure and alternatives in airspace at or above 3,000 feet, the ANMR review with respect to New Jersey is limited to airspace below 3,000 feet. The notice also described the FAA personnel involved in the ANMR and the function and scope of their duties as part of their review. The notice announced the dates (from November 5, 1991, through December 5, 1991) on which the FAA would convene 11 public hearings in New York and Connecticut. This Notice announced hearings in Staten Island, Cedarhurst, White Plains, Rye Brook, Queens and Newburgh.

By this notice, the FAA announces one additional phase of these hearings to be held in the State of New York. While all of these hearings have been open to all residents, the FAA has determined that the convenience of residents of the borough of the Bronx may be better served by adding a hearing location closer to them. These New York residents live adjacent to LaGuardia Airport, and are well within the study area mandated by Congress. The location selected is within the intended study area and consistent with the Congressional direction contained in the appropriations act cited above.

Written comments on the issues are encouraged and invited from persons or interested parties who are unable to attend the public hearings or who do now wish to make public statements. Written comments, which must be received on or before December 31, 1991, should be sent to: Federal Aviation Administration, Office of Air Traffic System Management (ATM-700), 800 Independence Avenue, SW., Washington, DC 20591.

Issued in Washington, DC on November 26, 1991.

Norbert A. Owens,

Deputy Associate Administrator for Air Traffic.

[FR Doc. 91-28982 Filed 12-2-91; 8:45 am]

BILLING CODE 4910-13-M

Radio Technical Commission for Aeronautics (RTCA); Special Committee 164; User Requirements for Future Airport and Terminal Area Communication, Navigation, and Surveillance Systems; Meeting

Pursuant to section 10(a) of the Federal Advisory Committee Act (Pub.L. 92-463, 5 U.S.C., appendix I), notice is hereby given for the thirteenth meeting of Special Committee 166 to be held December 17-18, 1991, in the RTCA conference room, 1140 Connecticut Avenue, NW., suite 1020, Washington, DC 20036, commencing at 9:30 a.m.

The agenda for this meeting is as follows: (1) Chairman's introductory remarks; (2) Approval of minutes of the twelfth meeting held on October 15-16, 1991, RTCA paper no. 543-91/SC166-178 (previously distributed); (3) Briefing on Cooperative Area Precision Landing System (CAPTS); (4) Briefing on Pilot Traffic Management (PTM) related to Visual Flight Rules (VFR) users; (5) Reports on action items assigned during previous committee meeting; (6) Report by chairman of Transition/Economics Working Group activity; (7) Review of sixth partial draft of committee report; (8) Assignment of tasks; (9) Other business; (10) Date and place of next meeting.

Attendance is open to the interested public but limited to space available. With the approval of the Chairman, members of the public may present oral statements at the meeting. Persons wishing to present statements or obtain information should contact the TRCA Secretariat, 1140 Connecticut Avenue, NW., suite 1020, Washington, DC. 20036; (202) 833-9339. Any member of the

public may present a written statement to the committee at any time.

Issued in Washington, DC, on November 25, 1991.

Joyce J. Gillen,

Designated Officer.

[FR Doc. 91-28914 Filed 12-2-91; 8:45 am]

BILLING CODE 4910-13-M

Intent to Rule

AGENCY: Federal Aviation Administration, DOT.

ACTION: Notice of intent to rule on application to impose a Passenger Facility Charge (PFC) at the Huntsville International Airport, Huntsville, Alabama.

SUMMARY: The Federal Aviation Administration (FAA) proposes to rule and invites public comment on the application to impose a PFC at Huntsville International Airport under the provisions of the Aviation Safety and Capacity Expansion Act of 1990 (Title IX of the Omnibus Budget Reconciliation Act of 1990) (Public Law 101-508) and 14 CFR part 158.

On November 19, 1991, the FAA determined that the application to impose a PFC submitted by the Huntsville-Madison County Airport Authority was substantially complete within the requirements of § 158.25 of part 158. The FAA will approve or disapprove the application, in whole or in part, no later than March 12, 1992.

DATES: Comments must be received on or before January 2, 1992.

ADDRESSES: Comments on this application may be mailed or delivered in triplicate to the FAA at the following address: FAA/Airports District Office, 120 North Hangar Drive, suite B, Jackson, Mississippi 39208-2306.

In addition, one copy of any comments submitted to the FAA must be mailed or delivered to Mr. Eugene B. Conrad, Jr., A.A.E., Executive Director of the Huntsville-Madison County Airport Authority at the following address: Huntsville-Madison County Airport Authority, 1000 Glenn Hearn Blvd., Box 20008, Huntsville, Alabama 35824.

Comments from air carriers and foreign air carriers may be in the same form as provided to the Huntsville-Madison County Airport Authority under § 158.23 of part 158.

FOR FURTHER INFORMATION CONTACT: Wayne Atkinson, Assistant Manager, FAA/Airports District Office, 120 North Hangar Drive, suite B, Jackson, Mississippi 39208-2306; telephone number (601) 965-4628. The application may be reviewed in person at this same location.

SUPPLEMENTARY INFORMATION: The following is a brief overview of the application.

Level of the proposed PFC: $3.00.

Proposed charge effective date: June 1, 1992.

Proposed charge expiration date: December 1, 2019.

Total estimated PFC revenue: $24,617,126.

Brief description of proposed project(s): Acquire development land; construct access/security road extension; § 107.14 security improvements; expand air cargo apron; airport master plan update; construct maintenance/equipment storage building; rehabilitate west runway and apron; construct regional ARFF training facility; overlay Runway 18R-36L runway and associated taxiways; expand fire station; install directional signage; acquire ARFF vehicle; expand terminal building; replace terminal boiler; extend Runway 18L-36R; overlay general aviation apron.

Availability of Applciation: Any person may inspect the application in person at the FAA office listed above. In addition, any person may, upon request, inspect the application, notice and other documents germane to the application in person at the office of the Huntsville-Madison County Airport Authority.

Issued in Atlanta, Georgia, on November 19, 1991.

Stephen A. Brill,

Manager, Airports Division, Southern Region.

[FR Doc. 91-28915 Filed 12-2-91; 8:45 am]

BILLING CODE 4910-13-M

DEPARTMENT OF THE TREASURY

Office of the Secretary

[Department Circular—Public Debt Series—No. 37-91]

Treasury Notes of November 30, 1993, Series AH-1993; Interest Rate

Washington, November 21, 1991

1. Invitation for Tenders

1.1 The Secretary of the Treasury, under the authority of chapter 31 of title 31, United States Code, invites tenders for approximately $13,500,000,000 of United States securities, designated Treasury Notes of November 30, 1993, Series AH-1993 (CUSIP No. 912827 D3 3), hereafter referred to as Notes. The Notes will be sold at auction, with bidding on the basis of yield. Payment will be required at the price equivalent of the yield of each accepted bid. The interest rate on the Notes and the price equivalent of each accepted bid will be determiend in the manner described below. Additional amounts of the Notes may be issued to Federal Reserve Banks for their own account in exchange for maturing Treasury securities. Additional amounts of the Notes may also be issued at the average price to Federal Reserve Banks, as agents for foreign and international monetary authorities.

2. Description of Securities

2.1 The Notes will be dated December 2, 1991, and will accrue interest from that date, payable on a semiannual basis on May 31, 1992, and each subsequent 6 months on November 30 and May 31 through the date that the principal becomes payable. They will mature November 30, 1993, and will not be subject to call for redemption prior to maturity. In the event any payment date is a Saturday, Sunday, or other nonbusiness day, the amount due will be payable (without additional interest) on the next business day.

2.2. The Notes are subject to all taxes imposed under the Internal Revenue Code of 1954. The Notes are exempt from all taxation now or hereafter imposed on the obligation or interest thereof by any State, any possession of the United States, or any local taxing authority, except as provided in 31 U.S.C. 3124.

2.3. The Notes will be acceptable to secure deposits of Federal public monies. They will not be acceptable in payment of Federal taxes.

2.4 The Notes will be issued only in book-entry form in a minimum amount of $5,000 and in multiples of that amount. They will not be issued in registered definitive or in bearer form.

2.5. The Department of the Treasury's general regulations governing United States securities, i.e., Department of the Treasury Circular No. 300, current revision (31 CFR part 306), as to the extent applicable to marketable securities issued in book-entry form, and the regulations governing book-entry Treasury Bonds, Notes, and Bills, as adopted and published as a final rule to govern securities held in the TREASURY DIRECT Book-Entry Securities System in Department of the Treasury Circular, Public Debt Series, No. 2-86 (31 CFR part 357), apply to the NOtes offered in this circular.

3. Sale Procedures

3.1. Tenders will be received at Federal Reserve Banks and Branches and at the Bureau of the Public Debt, Washington, DC 20239-1500, Monday, November 25, 1991, prior to 11 a.m.,

Eastern Standard time, for noncompetitive tenders and prior to 12 noon, Eastern Standard time, for competitive tenders. Noncompetitive tanders as defined below will be considered timely if postmarked no later than Sunday, November 24, 1991, and received no later than Monday, December 2, 1991.

3.2. The par amount of Notes bid for must be stated on each tender. The minimum bid is $5,000, and larger bids must be in multiples of that amount. Competitive tenders must also show the yield desired, expressed in terms of an annual yield with two decimals, e.g., 7.10%. Fractions may not be used. Noncompetitive tenders must show the term "noncompetitive" on the tender form in lieu of a specified yield.

3.3. A single bidder, as defined in Treasury's single bidder guidelines, shall not submit noncompetitive tenders totaling more than $5,000,000. A noncompetitive bidder may not have entered into an agreement, nor make an agreement to purchase or sell or otherwise dispose of any noncompetitive awards of this issue being auctioned prior to the designated closing time for receipt of competitive tenders.

3.4. The following institutions may submit tenders for accounts of customers if the names of the customers and the amount for each customer are furnished: depository institutions, as described in section 19(b)(1)(A), excluding those institutions described in subparagraph (vii), of the Federal Reserve Act (12 U.S.C. 461(b)); and government securities broker/dealers, registered with the Securities and Exchange Commission that are registered or noticed as government securities broker/dealers pursuant to section 15C(a)(1) of the Securities and Exchange Act of 1934, as amended by the Government Securities Act of 1986. Others are permitted to submit tenders only for their own account.

3.5. Tenders from bidders who are making payment by charge to a funds account at a Federal Reserve Bank and tenders from bidders who have an approved autocharge agreement on file at a Federal Reserve Bank will be received without deposit. In addition, tenders from States, and their political subdivisions or instrumentalities; public pension and retirement and other public funds; international organizations in which the United States holds membership; foreign central banks and foreign states; and Federal Reserve Banks will be received without deposit. Tenders from all others must be accompanied by full payment for the amount of Notes applied for, or by a guarantee from a commercial bank or a primary dealer of 5 percent of the par amount applied for.

3.6. Immediately after the deadline for receipt of competitive tenders, tenders will be opened, followed by a public announcement of the amount and yield range of accepted bids. Subject to the reservations expressed in section 4, noncompetitive tenders will be accepted in full, and then competitive tenders will be accepted, starting with those at the lowest yields, through successively higher yields to the extent required to attain the amount offered. Tenders at the highest accepted yield will be prorated if necessary. After the determination is made as to which tenders are accepted, an interest rate will be established, at a ⅛ of one percent increment, which results in an equivalent average accepted price close to 100.000 and a lowest accepted price above the original issue discount limit of 99.750. That stated rate of interest will be paid on all of the Notes. Based on such interest rate, the price on each competitive tender allotted will be determined and each successful competitive bidder will be required to pay the price equivalent to the yield bid. Those submitting noncompetitive tenders will pay the price equivalent to the weighted average yield of accepted competitive tenders. Price calculations will be carried to three decimal places on the basis of price per hundred, e.g., 99.923, and the determinations of the Secretary of the Treasury shall be final. If the amount of noncompetitive tenders received would absorb all or most of the offering, competitive tenders will be accepted in an amount sufficient to provide a fair determination of the yield. Tenders received from Federal Reserve Banks will be accepted at the price equivalent to the weighted average yield of accepted competitive tenders.

3.7. Competitive bidders will be advised of the acceptance of their bids. Those submitting noncompetitive tenders will be notified only if the tender is not accepted in full, or when the price at the average yield is over par.

4. Reservations

4.1. The Secretary of the Treasury expressly reserve the right to accept or reject any or all tenders in whole or in part, to allot more or less than the amount of Notes specified in section 1, and to make different percentage allotments to various classes of applicants when the Secretary considers it in the public interest. The Secretary's action under this section is final.

5. Payment and Delivery

5.1. Settlement for the Notes allotted must be made timely at the Federal Reserve Bank or Branch or at the Bureau of the Public Debt, wherever the tender was submitted. Settlement on Notes allotted will be made by a charge to a funds account or pursuant to an approved autocharge agreement, as provided in section 3.5. Settlement on Notes allotted to institutional investors and to others whose tenders are accompanied by a guarantee as provided in section 3.5. must be made or completed on or before Monday, December 2, 1991. Payment in full must accompany tenders submitted by all other investors. Payment must be in cash; in other funds immediately available to the Treasury; in Treasury notes or bonds maturing on or before the settlement date but which are not overdue as defined in the general regulations governing United States securities; or by check drawn to the order of the institution to which the tender was submitted, which must be received from institutional investors no later than Wednesday, November 27, 1991. When payment has been submitted with the tender and the purchase price of the Notes allotted is over par, settlement for the premium must be completed timely, as specified above. When payment has been submitted with the tender and the purchase price is under par, the discount will be remitted to the bidder.

5.2. In every case where full payment has not been completed on time, an amount of up to 5 percent of the par amount of Notes allotted shall, at the discretion of the Secretary of the Treasury, be forfeited to the United States.

5.3. Registered definitive securities tendered in payment for the Notes allotted and to be held in TREASURY DIRECT are not required to be assigned if the inscription on the registered definitive security is identical to the registration of the note being purchased. In any such case, the tender form used to place the Notes allotted in TREASURY DIRECT must be completed to show all the information required thereon, or the TREASURY DIRECT account number previously obtained.

6. General Provisions

6.1. As fiscal agents of the United States, Federal Reserve Banks are authorized, as directed by the Secretary of the Treasury, to receive tenders, to make allotments, to issue such notices as may be necessary, to receive payment for, and to issue, maintain,

service, and make payment on the Notes.

6.2. The Secretary of the Treasury may at any time, supplement or amend provisions of this circular if such supplements or amendments do not adversely affect existing rights of holders of the Notes. Public announcement of such changes will be promptly provided.

6.3. The Notes issued under this circular shall be obligations of the United States, and, therefore, the faith of the United States Government is pledged to pay, in legal tender, principal and interest on the Notes.

Gerald Murphy,

Fiscal Assistant Secretary.

[FR Doc. 91-28957 Filed 11-27-91; 2:42 pm]

BILLING CODE 4810-40-M

[Department Circular—Public Debt Series—No. 38-91]

Treasury Notes of November 30, 1996, Series V-1996; Interest Rate

November 21, 1991.

1. Invitation for Tenders

1.1 The Secretary of the Treasury, under the authority of chapter 31 of title 31, United States Code, invites tenders for approximately $9,000,000,000 of United States securities, designated Treasury Notes of November 30, 1996, Series V-1996 (CUSIP No. 912827 D4 1), hereafter referred to as Notes. The Notes will be sold at auction, with bidding on the basis of yield. Payment will be required at the price equivalent of the yield of each accepted bid. The interest rate on the Notes and the price equivalent of each accepted bid will be determined in the manner described below. Additional amounts of the Notes may be issued to Federal Reserve Banks for their own account in exchange for maturing Treasury securities. Additional amounts of the Notes may also be issued at the average price to Federal Reserve Banks, as agents for foreign and international monetary authorities.

2. Description of Securities

2.1. The Notes will be dated December 2, 1991, and will accrue interest from that date, payable on a semiannual basis on may 31, 1992, and each subsequent 6 months on November 30 and May 31 through the date that the principal becomes payable. They will mature November 30, 1996, and will not be subject to call for redemption prior to maturity. In the event any payment date is a Saturday, Sunday, or other nonbusiness day, the amount due will be payable (without additional interest) on the next business day.

2.2 The Notes are subject to all taxes imposed under the Internal Revenue Code of 1954. The Notes are exempt from all taxation now or hereafter imposed on the obligation or interest thereof by any State, any possession of the United States, or any local taxing authority, except as provided in 31 U.S.C. 3124.

2.3. The Notes will be acceptable to secure deposits of Federal public monies. They will not be acceptable in payment of Federal taxes.

2.4. The Notes will be issued only in book-entry form in a minimum amount of $1,000 and in multiples of that amount. They will not be issued in registered definitive or in bearer form.

2.5. The Department of the Treasury's general regulations governing United States securities, i.e., Department of the Treasury Circular No. 300, current revision (31 CFR part 306), as to the extent applicable to marketable securities issued in book-entry form, and the regulations governing book-entry Treasury Bonds, Notes, and Bills, as adopted and published as a final rule to govern securities held in the TREASURY DIRECT Book-Entry Securities System in Department of the Treasury Circular, Public Debt Series, No. 2-86 (31 CFR part 357), apply to the Notes offered in this circular.

3. Sale Procedures

3.1. Tenders will be received at Federal Reserve Banks and Branches and at the Bureau of the Public Debt, Washington, DC 20239-1500, Tuesday, November 26, 1991, prior to 12 noon, Eastern Standard time, for noncompetitive tenders and prior to 1 p.m., Eastern Standard time, for competitive tenders. Noncompetitive tenders as defined below will be considered timely if postmarked no later than Monday, November 25, 1991, and received no later than Monday, December 2, 1991.

3.2. The par amount of Notes bid for must be stated on each tender. The minimum bid is $1,000, and larger bids must be in multiples of that amount. Competitive tenders must also show the yield desired, expressed in terms of an annual yield with two decimals, e.g., 7.10%. Fractions may not be used. Noncompetitive tenders must show the term "noncompetitive" on the tender form in lieu of a specified yield.

3.3. A single bidder, as defined in Treasury's single bidder guidelines, shall not submit noncompetitive tenders totaling more than $5,000,000. A noncompetitive bidder may not have entered into an agreement, nor make an agreement to purchase or sell or otherwise dispose of any noncompetitive awards of this issue being auctioned prior to the designated closing time for receipt of competitive tenders.

3.4. The following institutions may submit tenders for accounts of customers if the names of the customers and the amount for each customer are furnished: Depository institutions, as described in section 19(b)(1)(A), excluding those institutions described in subparagraph (vii), of the Federal Reserve Act (12 U.S.C. 461(b)); and government securities broker/dealers, registered with the Securities and Exchange Commission that are registered or noticed as government securities broker/dealers pursuant to section 15C(a)(1) of the Securities and Exchange Act of 1934, as amended by the Government Securities Act of 1986. Others are permitted to submit tenders only for their own account.

3.5. Tenders from bidders who are making payment by charge to a funds account at a Federal Reserve Bank and tenders from bidders who have an approved autocharge agreement on file at a Federal Reserve Bank will be received without deposit. In addition, tenders from States, and their political subdivisions or instrumentalities; public pension and retirement and other public funds; international organizations in which the Untied States holds membership; foreign central banks and foreign states; and Federal Reserve Banks will be received without deposit. Tenders from all others must be accompanied by full payment for the amount of Notes applied for, or by a guarantee from a commercial bank or a primary dealer of 5 percent of the par amount applied for.

3.6. Immediately after the deadline for receipt of competitive tenders, tenders will be opened, followed by a public announcement of the amount and yield range of accepted bids. Subject to the reservations expressed in section 4, noncompetitive tenders will be accepted in full, and then competitive tenders will be accepted, starting with those at the lowest yields, through successively higher yields to the extent required to attain the amount offered. Tenders at the highest accepted yield will be prorated if necessary. After the determination is made as to which tenders are accepted, an interest rate will be established, at a ⅛ of one percent increment, which results in an equivalent average accepted price close to 100.000 and a lowest accepted price above the original issue discount limit of 99.000. That stated rate of interest will be paid on all of the Notes. Based on such interest rate, the price on each

competitive tender allotted will be determined and each successful competitive bidder will be required to pay the price equivalent to the yield bid. Those submitting noncompetitive tenders will pay the price equivalent to the weighted average yield of accepted competitive tenders. Price calculations will be carried to three decimal places on the basis of price per hundred, e.g., 99.923, and the determinations of the Secretary of the Treasury shall be final. If the amount of noncompetitive tenders received would absorb all or most of the offering, competitive tenders will be accepted in an amount sufficient to provide a fair determination of the yield. Tenders received from Federal Reserve Banks will be accepted at the price equivalent to the weighted average yield of accepted competitive tenders.

3.7. Competitive bidders will be advised of the acceptance of their bids. Those submitting noncompetitive tenders will be notified only if the tender is not accepted in full, or when the price at the average yield is over par.

4. Reservations

4.1. The Secretary of the Treasury expressly reserves the right to accept or reject any or all tenders in whole or in part, to allot more or less than the amount of Notes specified in Section 1, and to make different percentage allotments to various classes of applicants when the Secretary considers it in the public interest. The Secretary's action under this Section is final.

5. Payment and Delivery

5.1. Settlement for the Notes allotted must be made timely at the Federal Reserve Bank or Branch or at the Bureau of the Public Debt, wherever the tender was submitted. Settlement on Notes allotted will be made by a charge to a funds account or pursuant to an approved autocharge agreement, as provided in section 3.5. Settlement on Notes allotted to institutional investors and to others whose tenders are accompanied by a guarantee as provided in section 3.5. must be made or completed on or before Monday, December 2, 1991. Payment in full must accompany tenders submitted by all other investors. Payment must be in cash; in other funds immediately available to the Treasury; in Treasury notes or bonds maturing on or before the settlement date but which are not overdue as defined in the general regulations governing United States securities; or by check drawn to the order of the institution to which the tender was submitted, which must be received from institutional investors no later than Wednesday, November 27, 1991. When payment has been submitted with the tender and the purchase price of the Notes allotted is over par, settlement for the premium must be completed timely, as specified above. When payment has been submitted with the tender and the purchase price is under par, the discount will be remitted to the bidder.

5.2. In every case where full payment has not been completed on time, an amount of up to 5 percent of the par amount of Notes allotted shall, at the discretion of the Secretary of the Treasury, be forfeited to the United States.

5.3. Registered definitive securities tendered in payment for the Notes allotted and to be held in TREASURY DIRECT are not required to be assigned if the inscription on the registered definitive security is identical to the registration of the note being purchased. In any such case, the tender form used to place the Notes allotted in TREASURY DIRECT must be completed to show all the information required thereon, or the TREASURY DIRECT account number previously obtained.

6. General Provisions

6.1. As fiscal agents of the United States, Federal Reserve Banks are authorized, as directed by the Secretary of the Treasury, to receive tenders, to make allotments, to issue such notices as may be necessary, to receive payment for, and to issue, maintain, service, and make payment on the Notes.

6.2. The Secretary of the Treasury may, at any time, supplement or amend provisions of this circular if such supplements or amendments do not adversely affect existing rights of holders of the Notes. Public announcement of such changes will be promptly provided.

6.3. The Notes issued under this circular shall be obligations of the United States, and, therefore, the faith of the United States Government is pledged to pay, in legal tender, principal and interest on the Notes.

Gerald Murphy,

Fiscal Assistant Secretary.

[FR Doc. 91-28958 filed 11-27-91; 2:42 pm]

BILLING CODE 4810-40-M

Fiscal Service Surety Companies Acceptable on Federal Bonds

Rockwood Insurance Co.; Liquidation

Rockwood Insurance Company formerly held a Certificate of Authority as an acceptable surety on Federal bonds and was last listed as such at 52 FR 24623, July 1, 1987. The Company's authority was terminated by the Department of the Treasury effective June 30, 1988. Notice of the termination was published in the **Federal Register** of June 30, 1988, on page 24827.

On August 26, 1991, upon a petition by the Insurance Commissioner of the State of Pennsylvania, the Court issued an Order of Liquidation with respect to Rockwood Insurance Company. The Insurance Commissioner of the Commonwealth of Pennsylvania was appointed as the Liquidator. All persons having claims against Rockwood Insurance Company must file their claims, by April 26, 1992, or be barred from sharing in the distribution of assets.

All claims must be filed in writing and shall set forth the amount of the claim, the facts upon which the claim is based, any priorities asserted, and any other pertinent facts to substantiate the claim. It is recommended that Federal Agency claimants asserting priority status under 31 U.S.C. 3713 who have not yet filed their claim should do so, in writing, to: Department of Justice, Civil Division, Commercial Litigation Branch, P.O. Box 875, Ben Franklin Station, Washington, DC 20044-0875, Attn: Ms. Sandra P. Spooner, Deputy Director.

The above office will be consolidating any and all claims against Rockwood Insurance Company, on behalf of the United States Government. Any questions concerning filing of claims may be directed to Ms. Spooner at (202/FTS) 724-7194.

Questions concerning this notice may be directed to the Department of the Treasury, Financial Management Service, Funds Management Division, Surety Bond Branch, Washington, DC 20227, Telephone (202/FTS) 874-6905.

Dated: November 25, 1991.

Charles F. Schwan, III,

Director, Funds Management Division, Financial Management Service.

[FR Doc. 91-28853 Filed 12-2-91; 8:45 am]

BILLING CODE 4810-35-M

Sunshine Act Meetings

Federal Register
Vol. 56, No. 232
Tuesday, December 3, 1991

This section of the FEDERAL REGISTER contains notices of meetings published under the "Government in the Sunshine Act" (Pub. L. 94-409) 5 U.S.C. 552b(e)(3).

COMMODITY FUTURES TRADING COMMISSION

TIME AND DATE: 11 a.m., Friday, December 27, 1991.

PLACE: 2033 K St., NW., Washington, DC, 8th Floor Hearing Room.

STATUS: Closed.

MATTERS TO BE CONSIDERED: Surveillance Matters.

CONTACT PERSON FOR MORE INFORMATION: Jean A. Webb, 254-6314.

Jean A. Webb,
Secretary of the Commission.
[FR Doc. 91-29024 Filed 11-29-91; 10:24 am]
BILLING CODE 6351-01-M

COMMODITY FUTURES TRADING COMMISSION

TIME AND DATE: 11:00 a.m., Friday, December 20, 1991.

PLACE: 2033 K St., NW., Washington, DC, 8th Floor Hearing Room.

STATUS: Closed.

MATTERS TO BE CONSIDERED: Surveillance Matters.

CONTACT PERSON FOR MORE INFORMATION: Jean A. Webb, 254-6314.

Jean A. Webb,
Secretary of the Commission.
[FR Doc. 91-29025 Filed 11-29-91; 10:24 am]
BILLING CODE 6351-01-M

AGENCY HOLDING THE MEETING: Commodity Futures Trading Commission.

TIME AND DATE: 11:00 a.m., Friday, December 13, 1991.

PLACE: 2033 K St., N.W., Washington, D.C., 8th Floor Hearing Room.

STATUS: Closed.

MATTERS TO BE CONSIDERED: Surveillance Matters.

CONTACT PERSON FOR MORE INFORMATION: Jean A. Webb, 254-6314.

Jean A. Webb,
Secretary of the Commission.
[FR Doc. 91-29026 Filed 11-29-91; 10:24 am]
BILLING CODE 6351-01-M

COMMODITY FUTURES TRADING COMMISSION

TIME AND DATE: 11:00 A.M., Friday, December 6, 1991.

PLACE: 2033 K St., NW., Washigton, DC, 8th Floor Hearing Room.

STATUS: Closed.

MATTERS TO BE CONSIDERED: Surveillance Matters.

CONTACT PERSON FOR MORE INFORMATION: Jean A. Webb, 254-6314.

Jean A. Webb,
Secretary of the Commission.
[FR Doc. 91-29027 Filed 11-29-91; 10:24 45 am]
BILLING CODE 6351-01-M

COMMODITY FUTURES TRADING COMMISSION

TIME AND DATE: 10:00 a.m., Monday, December 9, 1991.

PLACE: 2033 K St., NW., Washington, DC, 8th Floor Hearing Room.

STATUS: Closed.

MATTERS TO BE CONSIDERED: Enforcement Meeting.

CONTACT PERSON FOR MORE INFORMATION: Jean A. Webb, 254-6314.

Jean A. Webb,
Secretary of the Commission.
[FR Doc. 91-29028 Filed 11-29-91; 10:24 am]
BILLING CODE 6351-01-M

DEPARTMENT OF ENERGY

FEDERAL ENERGY REGULATORY COMMISSION

"FEDERAL REGISTER" CITATION OF PREVIOUS ANNOUNCEMENT: November 25, 1991, 56 FR 59326.

PREVIOUSLY ANNOUNCED TIME AND DATE OF MEETING: November 27, 1991, 10 a.m.

CHANGE IN THE MEETING: The following Docket Numbers have been added to Items CAG-49, CAG-76, and CAG-81 on the Agenda scheduled for November 27, 1991:

Item No., Docket No., and Company

CAG-49—RP92-1-000, Northern Natural Gas Company
CAG-76—RP92-11-000, Southern Natural Gas Company
CAG-81—CP91-2315-001, Boston Gas Company

Lois D. Cashell,
Secretary.
[FR Doc. 91-29007 Filed 11-27-91; 5:06 pm]
BILLING CODE 6717-02-M

BOARD OF GOVERNORS OF THE FEDERAL RESERVE SYSTEM

TIME AND DATE: 11 a.m., Monday, December 9, 1991.

PLACE: Marriner S. Eccles Federal Reserve Board Building, C Street entrance between 20th and 21st Streets, N.W., Washington, D.C. 20551.

STATUS: Closed.

MATTERS TO BE CONSIDERED:

1. Personnel actions (appointments, promotions, assignments, reassignments, and salary actions) involving individual Federal Reserve System employees.
2. Any items carried forward from a previously announced meeting.

CONTACT PERSON FOR MORE INFORMATION: Mr. Joseph R. Coyne, Assistant to the Board; (202) 452-3204. you may call (202) 452-3207, beginning at approximately 5 p.m. two business days before this meeting, for a recorded announcement of bank and bank holding company applications scheduled for the meeting.

Dated: November 29, 1991.

William W. Wiles,
Secretary of the Board.
[FR Doc. 91-29111 Filed 11-29-91; 4:03 pm]
BILLING CODE 6210-01-M

INTERSTATE COMMERCE COMMISSION

Commission Conference

TIME AND DATE: 10:00 a.m., Tuesday, December 10, 1991.

PLACE: Hearing Room A, Interstate Commerce Commission, 12th & Constitution Avenue, NW., Washington, D.C. 20423.

STATUS: The Commission will meet to discuss among themselves the following agenda items. Although the conference is open for the public observation, no public participation is permitted.

MATTERS TO BE DISCUSSED:

Docket No. AB-167 (Sub-No. 1094), *Chelsea Property Owners—Abandonment—Portion of the Consolidated Rail Corporation's West 30th Street Secondary Track in New York, NY.*

EX Parte No. 346 (Sub-No. 26), *Association of American Railroads—Petition to Exempt Industrial Development Activities from 49 U.S.C. 10761(a), 10762(a)(1) 11902, 11903, and 11904(a).*

Ex Parte No. MC-203, *Petition to Amend 49 CFR 1057—Lease and Interchange of Vehicles.*

CONTACT PERSON FOR MORE INFORMATION: A. Dennis Watson, Office

of External Affairs, Telephone: (202) 275-7252, TDD: (202) 275-1721.

Sidney L. Strickland, Jr.,

Secretary

[FR Doc. 91-29056 Filed 11-29-91 1:00 pm]

BILLING CODE 7035-01-M

SECURITIES AND EXCHANGE COMMISSION

Agency Meeting

Notice is hereby given, pursuant to the provisions of the Government in the Sunshine Act, Pub. L. 94-409, that the Securities and Exchange Commission will hold the following meeting during the week of December 2, 1991.

A closed meeting will be held on Tuesday, December 3, 1991, at 2:30 p.m.

Commissioners, Counsel to the Commissioners, the Secretary to the Commission, and recording secretaries will attend the closed meeting. Certain staff members who have an interest in the matters may also be present.

The General Counsel of the Commission, or his designee, has certified that, in his opinion, one or more of the exemptions set forth in 5 U.S.C. 552b(c)(4), (8), (9)(A) and (10) and 17 CFR 200.402(a)(4), (8), (9)(i) and (10), permit consideration of the scheduled matters at a closed meeting.

Commissioner Fleischman, as duty officer, voted to consider the items listed for the closed meeting in a closed session.

The subject matter of the closed meeting scheduled for Tuesday, December 3, 1991, at 2:30 p.m., will be:

Institution of administrative proceedings of an enforcement nature.

Settlement of administrative proceedings of an enforcement nature.

Institution of injunctive actions.

Settlement of injunctive actions.

Litigation matter.

At times, changes in Commission priorities require alterations in the scheduling of meeting items. For further information and to ascertain what, if any, matters have been added, deleted or postponed, please contact: Edward Pittman at (202) 272-2400.

Dated: November 27, 1991.

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 91-29055 Filed 11-29-91; 12:59 pm]

BILLING CODE 8010-01-M

federal register

Tuesday
December 3, 1991

Part II

Environmental Protection Agency

40 CFR Parts 72, 73, 75 and 77

Acid Rain Program: Permits, Allowance System, Continuous Emissions Monitoring, and Excess Emissions; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

Office of Air and Radiation

40 CFR Parts 72, 73, 75, and 77

[FRL-4028-1]

Acid Rain Program: Permits, Allowance System, Continuous Emissions Monitoring, and Excess Emissions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rules.

SUMMARY: Title IV of the Clean Air Act, as amended by Public Law 101-549, the Clean Air Act Amendments of 1990 (the Act), authorizes the Environmental Protection Agency (EPA or Agency) to establish an acid rain program to reduce the adverse effects of acidic deposition. In order to implement this statutory mandate, the acid rain program requirements will eventually be codified in six regulations. Today's notice includes four proposed rulemakings: the permits regulation (40 CFR part 72); the allowance system regulation (40 CFR part 73); the continuous emissions monitoring regulation (40 CFR part 75); and the excess emissions penalties regulation (40 CFR part 77). These rulemakings constitute the core of the acid rain program with its four interrelated components: the permit, which includes a source's emissions control plans and requirements and allows a source to benefit from the allowance trading system; the allowance system, which provides a source the flexibility to meet its sulfur dioxide (SO_2) emissions limitation requirements economically while providing environmental accountability for collective compliance with the national cap on SO_2 emissions; the continuous emissions monitoring system, which not only ensures source compliance but also instills confidence in the market-based approach by certifying the existence of the "commodity" being traded; and the excess emissions program, which defines the consequences for failing to comply with the acid rain program's SO_2 and nitrogen oxides (NO_x) emissions requirements. Not included in today's **Federal Register** are the NO_x control program and the requirements for sources that elect to participate by "opting-in" to the acid rain program.

DATES: *Comments:* Comments on the rule proposed by this notice must be received on or before February 3, 1992; although written comments should be submitted separately for each rule, the Agency will hold three public hearings on all of today's proposal. The hearings are scheduled to convene at three different locations (addresses are listed below) and at the dates indicated below:

1. January 6 and 7, 1992, in Washington DC.
2. January 8, 1992, in San Francisco, California.
3. January 9 and 10, 1992, in Chicago, Illinois.

The hearings, with the exception of the second day in Washington, DC, will begin at 9:30 a.m., with registration at 9 a.m. The second day of public hearings in Washington, DC will begin at 12 noon, with registration at 11:30 a.m. The hearings will end at 4:30 p.m., unless concluded earlier. Requests to present oral testimony must be received on or before one week prior to final hearing date. Although the Washington, DC and Chicago, IL hearings are scheduled for two days, the second day will only proceed if there are more confirmed presenters than can be accommodated in one day. To schedule oral testimony and register attendance regarding the hearings, contact EPA's Public Hearings Hotline, 6 Whitmore Street, Arlington, MA 02174; telephone (617) 641-5375. Callers will receive by mail confirmation of their scheduled testimony and logistical information. Persons who wish to make oral presentations must restrict presentations to 10 minutes and are also encouraged to have written copies of their complete comments for inclusion in the official record. Written comments may be mailed prior to the scheduled hearings to the Hearings Hotline at the above address.

ADDRESSES: All written comments on these acid rain rules must be identified with the appropriate document control number and must be submitted in duplicate to: EPA Air Docket (LE-131), Environmental Protection Agency, 401 M St., SW., Washington, DC 20460. Written comments on the Permits rule must be identified with the document control number "A-90-38"; written comments on the Allowance System rule must be identified with the document control number "A-91-43"; written comments on the Continuous Emissions Monitoring rule must be identified with the document control number "A-90-51"; and written comments on the Excess Emissions rule must be identified with the document control number "A-91-68". Commenters may have comments on the acid rain program or the core rules in general; such comments may be sent to the Acid Rain Core Rules—General Docket, and must be identified with the document control number "A-91-69".

In addition, commenters may wish to call the Acid Rain Hotline at (617) 641-5377 to request information or ask general questions.

Comments received on these proposed rules will be available for reviewing and copying from 8:30 a.m. to 12 p.m. and 1:30 p.m. to 3:30 p.m., Monday through Friday, excluding legal holidays, in room M-1500, first floor Waterside Mall, at the address given above.

The public hearings are scheduled to convene at three different locations (the dates are listed above):

1. EPA Education Center, Waterside Mall, 401 M Street, SW., Washington, DC.
2. Westin St. Francis, 335 Powell Street, in San Francisco, California.
3. The Museum of Science and Industry, 57th and Lake Shore Drive, Chicago, Illinois.

FOR FURTHER INFORMATION CONTACT: Brian McLean, Director, Acid Rain Division (ANR-445), U.S. Environmental Protection Agency, 401 M Street, SW., Washington, DC 20460, (617) 641-5377.

SUPPLEMENTARY INFORMATION: The contents of this preamble are as follows:

I. Statutory Authority

Title IV of the Clean Air Act, as amended by Public Law 101–549, the Clean Air Act Amendments of 1990, authorizes the Environmental Protection Agency to establish the acid rain program to reduce the adverse effects of acidic deposition.

II. General Background

Acid rain is the accepted term which encompasses a complex set of phenomena that begins with fossil fuel emissions, includes the transport and transformation of those emissions through the atmosphere, and ends with the effects of those emissions and their resulting transformation products on the environment. Specifically, the burning of fossil fuels, particularly coal and oil, releases emissions of sulfur dioxide (SO_2) and nitrogen oxide (NO_x) into the atmosphere. In the atmosphere, SO_2 and NO_x may undergo various chemical reactions, resulting in the transformation of the emissions into chemical products including sulfates, nitrates, sulfuric acid and nitric acid. These compounds can fall to earth near the source or be transported hundreds of miles. They may be deposited during any stage of their transformation, returning to earth as dry deposition in the form of gases, aerosols, and particles as well as wet deposition through precipitation such as rain, fog, or snow. The presence of these emissions and their transformation products in the atmosphere contributes to reduced visibility and is suspected of posing a threat to human health at current levels. The acidic deposition resulting from SO_2 and NO_x emissions and their byproducts damages both ecosystems and man-made materials. Of the approximately 23 million tons of SO_2 and 19 million tons of NO_x emitted annually from all sources in the United States in 1985, about 16 million tons of SO_2 and 7 million tons of NO_x were emitted by electric utilities.

Title IV of the Act authorizes EPA to establish the acid rain program to reduce the adverse effects of acidic deposition. Specifically, the Act mandates a national emissions cap of 8.95 million tons per year on electric utility SO_2 emissions, to be achieved in two phases. In Phase I, which begins in 1995, the 110 largest, highest-emitting utility plants, located in 21 States, must meet an intermediate SO_2 emissions limitation requirement. By 2000, the start of Phase II, virtually all existing utility units with output capacity greater than 25 megawatts and all new utility units will be required to meet emissions limitations. As a result, total annual SO_2 emissions will be reduced by 10 million tons below 1980 levels. In addition, SO_2 sources not explicitly affected by Phase II requirements (e.g. industrial facilities) may elect to participate by "opting-in" to the acid rain program. Title IV also requires that certain coal-fired electric utility boilers reduce their emissions of NO_x through installation of low NO_x burner technologies or their equivalent, at the same time they are required to comply with the SO_2 limitations.

The acid rain program requirements will be codified in six regulations:

Acid rain regulation	40 CFR part No.
Permits	72
Allowance system	73
Opt-in	74
Continuous emissions monitoring	75
Nitrogen oxides control	76
Excess emissions	77

The rules for opt in and for NO_x control are reserved for future rulemaking actions. In addition, 40 CFR part 78 is reserved for the acid rain program. EPA is soliciting comment on whether to use part 78 to contain the appeals procedures for the acid rain program, which are proposed in today's notice as one subpart of the permits rule (Subpart H, 40 CFR part 72).

Today's notice covers four proposed rulemakings: permits (40 CFR part 72); the allowance system (40 CFR part 73); continuous emissions monitoring (40 CFR part 75); and excess emissions (40 CFR part 77). Following the general discussion of the acid rain program in this preamble, the reader will find specific discussions tailored to each of the four proposed rulemakings, in order. The reader is directed to send comments on either the proposed rulemakings or the corresponding sections of this preamble to the appropriate docket, as listed in the Addresses section above. If the reader has comments on more than one rulemaking and corresponding section of the preamble, then the reader is encouraged to submit separate comments to the appropriate dockets; at a minimum, if the reader prepares one

combined set of comments, then the reader is requested to send duplicate copies of such comments to each of the appropriate dockets.

In order to implement the statutory mandate to develop the acid rain program, EPA solicited comments and ideas from many individuals and organizations. To facilitate detailed discussions, EPA formed the Acid Rain Advisory Committee (ARAC) under the authority of the Federal Advisory Committee Act (5 U.S.C. (app. I) 9(c)) in November of 1990. This Committee included 44 members representing various stakeholder groups, including utilities, emissions control equipment vendors, State Public Utility Commissioners, academicians, coal companies, State air pollution control agencies, labor, and environmental groups. In addition to the Committee members, several hundred people attended the six ARAC sessions, which were held as public meetings, and participated in varying degrees in the discussions. EPA found the ARAC process to be extremely helpful to the Agency in drafting these acid rain program regulations. (For further information about ARAC deliberations, please refer to Air Docket #A-90-39.)

III. Acid Rain Regulations Introduction

The centerpiece of the acid rain program is an innovative trading system with a fixed number of fully marketable allowances. An allowance authorizes the emission of one ton of SO_2. Existing utility sources are allocated allowances based on their historic fuel use and the emissions limitations specified in the Act. Utility units must not emit SO_2 in quantities that exceed the number of allowances they hold. The allowance system regulation (40 CFR part 73) includes several components, some of which are being proposed on differing time schedules, as listed below:

ALLOWANCE SYSTEM RULE

[40 CFR Part 73]

Subpart	Proposed rule (date published)	Final rule (target date for publication)
A: Background	[insert today's date].	May, 1992.
B: Allocation	March, 1992	December, 1992.
C: Tracking	[insert today's date].	May, 1992.
D: Transfers	[insert today's date].	May, 1992.
E: Auction and sales.	May 23, 1991	November, 1991.
F: Conservation and renewable energy reserve.	[insert today's date].	May, 1992.
G: Small diesel refineries.	March, 1992	December, 1992.

The allowance background component (subpart A) of the allowance system regulation covers general information, such as applicability and definitions. The allowance allocation component (subpart B) of the allowance system regulation, which is reserved for future rulemaking action, will include the assignment of allowances to affected sources each year. The allowance tracking component (subpart C) of the allowance regulation covers the function and content of allowance accounts as well as the responsibilities of authorized agents for the allowance accounts. The allowance transfers component (subpart D) of the allowance regulation covers the recordation and notification requirements for the certified transfer of allowances. The allowance auction and sale component (already proposed on May 23, 1991, in 56 FR pp 23744-23759 as subpart D, and renamed in today's proposal as subpart E) includes the requirements for the direct purchase of allowances from an EPA sponsored auction or sale. The requirements for the demonstration of energy savings from conservation or use of renewable energy which must be met in order to apply for allowances are contained in the Conservation and Renewable Energy Reserve component (subpart F) of the allowance system regulation. Finally, the Small Diesel Refineries component (subpart G) of the allowance system regulation, which is reserved for future rulemaking action, will include allowance application requirements for such refineries. Today's proposal includes the primary structure of the allowance system (background, tracking, and trading) and the requirements for applying for allowances from the conservation and renewable energy reserve.

Since allowances are fully transferrable, utilities may meet their emissions control requirements in the most cost-effective manner possible. However, because the Act explicitly specifies annual SO_2 emissions tonnage limitations for each affected utility unit, in order to operate and to trade allowances each affected source must apply for a permit which, among other things, certifies that the source will hold a sufficient number of allowances to cover its SO_2 emissions, or specifies the source's alternate planned method of compliance. The permit regulation will be codified in 40 CFR part 72.

In order to ensure that source compliance collectively results in the achievement of the nationally mandated reductions in SO_2 and NO_x emissions, each affected source is required to install a system to continuously monitor the concentration and flow of emissions, in order to collect, record, and report emissions data. The continuous emissions monitoring rule will be codified in 40 CFR part 75.

Finally, if an affected unit exceeds its emissions limitation for either SO_2 or NO_x, the Act requires the affected source to pay penalties and, for SO_2, to meet emissions offset requirements. These requirements are designed to act as a strong incentive for compliance with the mandated emissions reductions of the acid rain program. The excess emissions penalties requirements will be codified in 40 CFR Part 77.

Because the acid rain program is designed to allow sources to meet the mandated emissions reductions in the most cost-effective manner possible, SO_2 sources not explicitly affected by the Act's requirements (e.g. industrial sources) may elect to participate in the allowance market by "opting in" to the acid rain program. The opt-in rule will be the subject of a separate future rulemaking (to be codified in 40 CFR part 74). Although opt-in sources may ultimately be subject to some or all of the core components of the acid rain program, all opt-in requirements, including any core rule requirements incorporated into part 74, will be established through the future rulemaking process. Accordingly, EPA strongly urges that no comments explicitly concerning the opt in program be submitted in response to the current proposal, since EPA will publish a complete notice of proposed rulemaking for the opt in rule in a separate rulemaking process.

The acid rain program addresses the annual average NO_x emissions rate requirements as a separate component of the program. Specifically, certain coal-fired electric utility boilers are required to reduce their emissions of NO_x through installation of low NO_x burner technologies or their equivalent. The NO_x control rule, which will be the subject of a future rulemaking, will be codified in 40 CFR part 76. However, procedures to apply for some of the NO_x

compliance options are addressed in the Permits rule proposed at 40 CFR part 72.

In summary, the four rules covering the core acid rain program requirements—the permit, the allowance system, the continuous emissions monitoring system, and the excess emissions program—are proposed in today's **Federal Register** following this notice.

IV. Permits Regulation

A. Overview of the Acid Rain Permit Program

Section 408(a) of the Clean Air Act, as amended by Public Law 101-549 (the Act) requires that the Acid Rain program, mandated by title IV of the Act, be implemented through operating permits. Acid Rain permits must ensure source accountability for the emissions reductions mandated by title IV of the Act, yet afford sources flexible planning opportunities to help minimize the costs of compliance. In addition, the Acid Rain permit program must integrate smoothly with State operating permits issued under programs approved pursuant to title V of the Act, yet ensure the national consistency necessary to support the allowance trading market.

1. Flexibility

The Agency believes that an active allowance trading market, supported by flexible compliance planning opportunities, will help affected sources to minimize compliance costs. EPA's goal is to structure simple, flexible and predictable Acid Rain permit program requirements that will promote these objectives. For example, today's proposal would allow source compliance plans that conditionally proposed the use of several alternative compliance options, with procedures and flexible deadlines for affected sources to notify EPA of their decision to rely on (i.e., to activate) one or more of the options. In addition, the proposal would establish expeditious methods for revising permits, consistent with the need for adequate public notice and comment, without undergoing lengthy modification procedures in every case, so that affected sources would be able to revise their permits to allow for more cost-effective compliance methods.

2. National Consistency

National consistency in implementation of the Acid Rain program requirements is necessary to ensure the effective functioning of a national allowance trading market. Inconsistent implementation could affect the value and fungibility of allowances across Regions, States, and localities. This, in turn, could impede the economies inherent in a national market. Today's proposal would, therefore, establish nationally standardized permitting. Standardized forms for permit applications, compliance plans, permits, and compliance certifications are one important mechanism proposed today by which national consistency would be achieved. In addition, to help ensure a nationally consistent body of judicial precedent, today's rule proposes that EPA be given notice of any challenges to Acid Rain permit conditions brought in State court during Phase II of the program, and an opportunity to intervene in the action.

3. Integration of Titles IV and V

Title V establishes a regime for State adoption and EPA approval of operating permit programs for implementing all air quality requirements of the Act (e.g., air toxics, State implementation plans, and during Phase II, Acid Rain standards). (See regulations proposed at 40 CFR part 70 May 10, 1991 56 FR 21712). The regulations proposed today at 40 CFR part 72 set forth requirements for affected sources to obtain Acid Rain permits, or the Acid Rain portion of permits issued under 40 CFR parts 70 or 71, under three different situations: (1) During Phase I, when EPA is the permitting authority; (2) during Phase II, when the State or local permitting authority issues a 40 CFR part 70 permit which includes a specific Acid Rain Section; and (3) during Phase II, when EPA is the permitting authority under 40 CFR part 71 where the State or local agency is not adequately administering or enforcing a 40 CFR part 70 program. In today's proposal EPA has, thus, endeavored to integrate the title IV and title V permit program requirements to the extent that such integration is practicable, is authorized by the statute, and is consistent with the national allowance program, in order to facilitate Federal approval of and transition to State operating permit programs.

Acid Rain permits are required to be issued in accordance with title V, except "as modified by" the Acid Rain program requirements of title IV. (See, sections 408(a) and 506(b) of the Act.) Section 506(b) of title V states that "The provisions of this title, including provisions regarding schedules for submission and approval or disapproval of permit applications, shall apply to permits implementing the requirements of title IV except as modified by that title." Parallel provisions appear throughout section 408, including Subsection 408(a) which provides that the Acid Rain program "shall be implemented, subject to section 403, (dealing with allowances) by permits issued * * * in accordance with the provisions of title V, as modified by this title." These provisions clarify that title V permits cannot be used to modify or revoke the fundamental requirements of the Acid Rain program, including allowance allocations granted under the authority of title IV. These provisions also clearly express a strong Congressional intent for the Title IV permit and allowance programs to modify title V, as necessary, to ensure the integrity of the Acid Rain program, including the orderly functioning of the allowance system. (The title IV authority to modify provisions of title V, however, does not apply to requirements found in other titles of the Act that are merely implemented through title V. For example, title I State Implementation Plan requirements to which an Acid Rain source is subject cannot be modified by the authority given in section 408(a)).

Sections 403(f) and 413 of the Act require that nothing in the Acid Rain permit (or in the Acid Rain portion of a 40 CFR part 70 or 71 permit) would alter any other Clean Air Act requirement, including those designed to protect the National Ambient Air Quality Standards (NAAQS) (e.g., the applicable State Implementation Plan (SIP) limitation). An Acid Rain source may operate flexibly within the allowance trading system, but nothing in the Acid Rain program would excuse non-compliance with any other requirements of the Act. In addition, today's proposal would provide the opportunity for public notice and comment on permit procedure actions as required by title V. Finally, consistent with title V, today's proposal includes permit forms that would be used for the Acid Rain portion of a permit. This approach should help ensure a smooth transition between Phase I EPA and Phase II State permitting, and reduce opportunities for confusion and delay.

Thus, today's proposal includes Acid Rain-specific permit procedures and requirements that would apply to States issuing Clean Air Act permits under programs approved pursuant to title V of the Act. For example, the rule would require that the Acid Rain permit provisions appear in a separate, stand-alone portion of the State-issued permit, using standardized forms. In addition, each permit would have to prohibit affected units from emitting sulfur dioxide (SO_2) in excess of the allowances held for that unit, consistent with section 403(f) and other sections of title IV. As provided in title IV, today's

proposal would require compliance by affected sources and States with the statutorily mandated schedules for permitting and permit terms, and would require, as provided in sections 408(c)(1)(A) and 408(d)(3), that proposed Acid Rain permit applications and compliance plans be binding on affected sources until approved or superseded by a permit. Today's proposal also includes a limitation, pursuant to section 408(h)(2) and section 504(f), that if a permit shield is applied to a permit by the permitting authority under section 504(f) of the Act, it would only apply with regard to Acid Rain permit terms that unambiguously comply with 40 CFR parts 72–78.

How to synchronize the State's timing of issuing title V permits so that permitting for future title IV requirements occurs at the same time as permitting for other Clean Air Act requirements is also addressed below in the discussion of subpart I of today's proposal. Phase I permits, which will be issued by the Administrator, will be issued in 1993 with a five-year term of 1995 through 1999. Pursuant to title IV, State permitting authorities are required to issue title V permits containing Phase II SO_2 requirements to all affected sources by December 31, 1997. States must also begin processing Phase II Acid Rain NO_x permit applications in 1998. Pursuant to title V, within four years after a State receives EPA approval of its title V permit program, it must complete the process of issuing title V permits for all Clean Air Act requirements to all affected sources in its jurisdiction. Today's preamble describes three approaches States may choose from to coordinate the permitting of title IV and other Clean Air Act requirements for affected sources. States would be free to choose from any of these approaches or to use any other approach provided it is consistent with the requirements and deadlines for permitting contained in titles IV and V of the Act.

4. Accountability

The Agency plans to ensure accountability by requiring strict compliance with the stringent excess emissions offset and penalty requirements provided for in section 411 of the Act.[1] The excess emissions requirements are proposed today at 40 CFR part 77. Section 411 of the Act provides that for each ton of SO_2 or NO_x emitted in excess of an affected unit's emissions limitation, the source must pay a statutory base penalty of $2000. This penalty is estimated to be more than twice the expected market value of an allowance. In addition, a unit with excess emissions of SO_2 will be required to expeditiously offset the excess tons emitted. For SO_2 excess emissions, EPA must automatically deduct allowances from the affected unit's account absent an approved alternative offset plan. The Agency believes that the economic implications of these stringent requirements, along with the risk of additional enforcement, will go far to ensure accountability in the program. EPA also plans to ensure strict compliance by affected sources with other requirements of the program, such as the control obligations that apply to Phase I extension units under section 404(d)(7), and the shared responsibility, as specified in the rule, of the designated representative and multiple owners and operators of affected units for ensuring compliance with the program. Other provisions of today's proposal intended to ensure accountability while maintaining the program's overall flexibility include the rule's heavy reliance on certifications by the designated representative on behalf of owners and operators of affected sources and affected units, and the liability provisions pertaining to multi-unit compliance plans. In addition, while allowing flexible revisions to the permits, the rule provides that no revision can excuse a past violation of a requirement.

[1] As is stated in section 411(e) of the Act, the requirements of section 411 are in addition to the Act's other enforcement authorities.

5. Organization of the Rule

The Acid Rain permit program regulations proposed today at 40 CFR part 72 cover applicability, definitions, and other general provisions; Acid Rain designated representative certification procedures and obligations; Acid Rain permit applications and compliance planning requirements; Acid Rain compliance options; Acid Rain permit contents; Acid Rain Phase I implementation; Federal Acid Rain permit issuance procedures; Federal Acid Rain permit appeals procedures; Acid Rain Phase II implementation; Acid Rain permit revision requirements; and Acid Rain compliance certification requirements. In addition, standardized permit program forms are proposed. The organization of the preamble follows the organization of the proposed rule which is presented in loosely chronological order. Thus, since designated representatives must be certified before permits can be issued, (See section 408(i) of the Act), the proposed requirements concerning designated representative appear first (following general information). The proposed rule then goes through the proposed Phase I and Phase II requirements. Many requirements of the program would apply to both Phase I and Phase II. Where requirements would apply only to Phase I, they have been separated for the sake of clarity. Those sections will be inapplicable to Phase II sources unless they decide to participate early in the program pursuant to an Acid Rain compliance option as provided in proposed subpart D.

B. Acid Rain General Provisions

This subpart of the proposed rule includes a section describing to whom the Acid Rain permit program would apply; sections on definitions, measurements and abbreviations, addresses for permit program submissions, and availability of information; reservations of State and Federal authorities; and prohibitions.

1. Definitions

Today's proposal includes a number of definitions. These include definitions from title IV of the Act which are proposed to be incorporated into the regulations, as appropriate. EPA has also proposed definitions for a number of additional terms. Key definitions are discussed below in discussions of the relevant sections of the rule.

Additional definitions are discussed in the preamble for the other Acid Rain program regulations proposed today, and for the title V operating permits regulations at 40 CFR part 70. Language incorporating the definitions of the other Acid Rain program regulations and the Act by reference appears in each part of the Acid Rain program regulations proposed today, and is intended to assist in preserving program integrity. The terms that are proposed to be defined in 40 CFR part 72 specifically are those central to a clear understanding of the 40 CFR part 72 provisions.

2. Applicability

Section 72.7 of today's proposal describes the categories of units which would be subject to the program. The definitions in section 402 of the Act for "affected source", "affected unit", "unit", "utility unit", "existing unit" and "new unit" describe the sources that would be subject to Acid Rain requirements. This section relies on those definitions.

a. *"Existing" and "new units"*. The title IV definitions of "existing unit" and "new unit" are different from the definitions for these terms as used in the other programs under the Act (e.g., new source performance standards—NSPS—

under title I). Title IV defines new units as those which commence commercial operation on or after enactment (i.e., November 15, 1990), while new units under other titles of the Act generally are defined based on the date of proposal of a new source rule. Therefore, a unit could be classified as a new unit for purposes of NSPS requirements and as an existing unit for purposes of the Acid Rain program.

b. *Appendices A and B.* To facilitate implementation, today's proposal includes two appendices referenced in the applicability section of the rule (§ 72.7), which identify specific existing units subject to Acid Rain permitting. Appendix A includes Phase I affected units from Table A of title IV of the Act. Appendix B, which is based on section 405 of the Act, lists the additional existing units which are subject to Acid Rain permitting requirements during Phase II. Appendix B units could, however, be designated as affected units during Phase I under sections 404(b) and (c), and 408(c)(1)(B) of the Act, and would thereby be subject to the Phase I permitting requirements. Appendix B does not include units listed in appendix A or "new units" even though such units are also subject to Phase II of the program. The list of units in appendix B of today's proposal is preliminary and subject to revision. A more complete list of affected Phase II units is scheduled for proposal with the Allowance Allocation rule of 40 CFR part 73, subpart A, in December, 1991. Any comment on the inclusion or exclusion of specific units in appendix B should, therefore, be reserved for this future proposal rather than today's proposal. Moreover, today's proposal does not include information on the basic allowance allocations for the units listed in Appendices A and B, or the units' baselines, and the lesser of their actual or allowable 1985 emissions. This information will also be proposed with the December part 73 proposal.

c. *Units not subject to the acid rain program.* The proposal also identifies several categories of units which would not be subject to program requirements unless they elected to participate in the program, for example, pursuant to the opt-in provisions at 40 CFR part 74. This list of excepted categories of units is provided to further clarify the scope of the Acid Rain program.

d. *Applicability of program to specific categories of units.* The proposal clarifies the applicability of the program for two categories of units. The first category concerns units modified on or after enactment to serve a generator with a nameplate capacity of greater than 25MWe. The statutory definition of "existing unit" excludes any unit which only serves generators with a nameplate capacity of 25MWe or less. It does not, therefore, include units that were modified on or after enactment to serve one or more generators with a nameplate capacity of greater than 25MWe. The Agency proposes to treat any such unit as a "new unit". The Agency believes this interpretation is appropriate since treating such units as "existing units" would cause an exceedance of the 8.95 million ton cap on SO_2 emissions mandated in section 403 of the Act. Since "existing units" are allocated allowances, whereas "new units" are not, treating such units as "existing units" would also put the Phase II allowance calculations, which the Administrator is required to propose by the end of 1991, in question in perpetuity. If each modified 25MWe unit were classified as an "existing unit" at the time it was modified to serve a larger generator, an indefinite number of allowances would be needed in the future to accommodate such units. As defined in today's proposal, any such unit would be required to obtain allowances to cover SO_2 emissions and comply with the requirements of 40 CFR parts 72–78, as specified for new units. The Agency solicits comment on this issue.

The second category of units for which applicability is clarified in today's proposal is combined cycle units. The Agency proposes to exempt existing combined cycle units without auxiliary firing from Acid Rain permitting requirements by including them in the definition of "simple combustion turbine." Existing combined cycle units with auxiliary firing would not be included in this exemption and would, thus, be subject to Acid Rain permitting requirements. The Agency proposes to include combined cycle units without auxiliary firing in the definition of "simple combustion turbine" because of the similarity of their design characteristics. They are a minor reconfiguration of simple combustion turbines. In addition, they use fuel more efficiently than combined cycle units with auxiliary firing. The Agency believes that exempting this category of units from the Acid Rain program is, therefore, consistent with the environmental intent of the Act. By comparison, combined cycle units with auxiliary firing diverge enough in design from simple combustion turbines to make their inclusion in the definition of simple combustion turbine, and hence their exemption from Acid Rain permitting requirements, questionable. However, under today's proposal both types of combined cycle units as well as simple combustion turbines would be subject to Acid Rain program requirements in Phase II, (as new units) if such units commence commercial operation on or after November 15, 1990, because the statutory exemption for simple combustion turbines is only applicable to existing units. The Agency requests comment on the proposed treatment of combined cycle units.

Today's proposal specifies, in accordance with the Act, that any new unit, including a simple combustion turbine or a unit that serves one or more generators of 25MWe or less is subject to the requirements of the Acid Rain program. The Agency requests comment on the effect of this requirement on very small units, and on whether a de minimis exclusion should be included in the final rule. For example, such an exclusion might be appropriate for emergency generators used by hospitals that do not sell electricity during peak load periods.

e. *Applicability determinations.* The Agency is considering establishing informal procedures for issuing applicability determinations to sources seeking a final statement regarding whether or not they are subject to Acid Rain program requirements.

f. *Shared responsibility and accountability.* Under today's proposal, it will not be unusual for a number of "persons" within the meaning of the Act to be involved in common activities designed, at least in part, to achieve compliance with the Act. In this regard, the proposed rule affords the various persons a great deal of flexibility in designing appropriate compliance strategies. The Agency wishes here to clarify that, where there are violations in situations involving multiple persons, it will ordinarily focus its enforcement activities on persons responsible for the violations, where such responsibility is apparent from information in the possession of EPA. The Agency also notes the Act does not affect the right of such persons to contractually apportion the financial responsibility for liability based upon violations of the Act.

Under some circumstances, a party to a multi-unit compliance plan may have no responsibility for a particular violation. For example, under a reduced utilization plan involving a Phase I unit and one or more compensating units, if a designated compensating unit had emissions in excess of the allowances held in its Allowance Tracking System compliance subaccount, and the Phase I unit is in full compliance with its own permit and compliance plan obligations,

the Agency would focus its enforcement on the compensating unit.

g. *Submissions.* Section 72.9(a) would require that all non-electronic written Acid Rain program submissions be delivered by certified mail. The certified mail requirement is to ensure that an independent third party would have a record to verify the transmittal. Under this provision, submissions could be sent by traditional forms of postal delivery (e.g., U.S. Postal Service) as well as by private delivery services, provided the service maintains an independent record of delivery verification.

Reservation of Other Federal and State Authorities. Consistent with sections 403(f) and 413 of the Act, subpart A would also reserve State and Federal air quality authorities and requirements under other provisions of the Act, including section 116. This reservation is intended to ensure that nothing in the Acid Rain program, including an Acid Rain program permit provision, would excuse the source's obligation to comply with other, more stringent, requirements, for example, in a State implementation plan. In addition, subpart A clarifies that the provisions of title IV and the Acid Rain program rules are in addition to the Agency's authorities under other provisions of the Act.

C. Designated Representative

1. Role and Certification Requirement

Subpart B of today's proposal governs the process for certifying, and the duties of, the designated representative. As a prerequisite to obtaining a permit, section 408(i) of the Act requires that a designated representative for the owners and operators of each affected unit at the affected source file a certificate of representation with regard to Acid Rain matters. In addition, section 408 (c)(1) and (d)(2) require the designated representative for the affected source to submit the source's permit applications. Under subpart B, no more than one designated representative must be certified for each affected source. The designated representative would represent the owners and operators of each affected unit at the affected source, as well as the owners and operators of the affected source as a whole, in matters pertaining to the Acid Rain program including: each affected unit's and source's submission of and compliance with Acid Rain permits, permit applications, and compliance plans; and the holding, transfer and disposition of allowances for each affected unit at the affected source. These duties are consistent with the provisions of title IV, which require that the owners and operators of affected units act through a "designated representative" with respect to such matters.

The proposed rule interprets the statutory authorities, responsibilities, and duties of the designated representative as establishing a specific category of "operator" role. Under this reading, provisions of the statute requiring a common "owner or operator" (e.g., substitution plans, NO_x averaging) would be satisfied by having a common designated representative. This would be consistent with the traditionally broad interpretation of the term "operator" under the Clean Air Act, which has included any "person" acting in a supervisory or control authority (e.g., site supervisors, plant managers, operating companies). The interpretation proposed today would not, however, alter the fact that the designated representative's supervisory and control authorities are both specific in purpose and fiduciary nature. The designated representative would, thus, not be required by this interpretation to have any additional authorities or duties not contemplated by the statute and today's proposed rules (e.g., the designated representative could, but would not have to be, the plant manager). An alternative reading of the statutory language pertaining to the roles and functions of the "designated representative" would be that a designated representative is not by definition a type of "operator". Under this reading, the provisions in the statute requiring common ownership or operation could not be satisfied merely by having a common designated representative (unless, the designated representative was also an owner or operator of both units.) EPA requests comment on these alternative interpretations of the relationship of "designated representative" to "operator". In addition, the rule provides that the designated representative would be deemed to be the "responsible official" for an affected source with regard to Acid Rain permitting under title V and 40 CFR parts 70 and 71. (This provision should not be confused with the use of the term "responsible official" as proposed on May 23, 1991 in 40 CFR part 73, subpart E, and new subpart F. The Agency intends to prevent any confusion in this regard by changing any reference to "responsible official" in 40 CFR part 73, subpart E, and new subpart F to "certifying official" when promulgating that rule in final form.)

The role of the designated representative is of critical importance to the functioning of the program. By proposing to require all owners and operators of an affected source and of each affected unit at a source to interact with the Agency exclusively through one designated representative, the proposed rule would afford the regulated community maximum flexibility in compliance planning, and ensure the smooth functioning of the allowance system. At the same time, the proposed approach would simplify the Agency's administration of the program and ensure source accountability.

The Agency recognizes that the designated representative cannot always be available to perform his or her duties (e.g., due to illness). Therefore, the rule proposes to allow the owners and operators of an affected source to appoint an alternate designated representative to act on behalf of the designated representative when the designated representative is unavailable. The certificate of representation required to be submitted by the designated representative under subpart B must specify the name and other information identifying the alternate designated representative selected, and the alternate must sign the certificate. The rule specifies that in the event of concurrent and conflicting actions by the designated representative and the alternate, the Administrator shall deem the action of the designated representative as superseding. The rule also specifies how the alternate can be changed. Thus, unless expressly provided to the contrary, whenever the term "designated representative" is used in the rule, it should be read to apply to the alternate designated representative, if any, included in the certificate of representation.

The proposal would ensure that the Agency or State permitting authority could rely on submissions certified by the designated representative, without having to entertain or evaluate alternative submissions by individual owners or operators of the same unit or to seek separate concurrences by individual owners or operators. This approach should ensure a streamlined and expeditious permitting process and eliminate the need for lengthy inquiries into unit ownership before a permit could be issued. Similarly, participants in the allowance market would be able to rely on representations made by the designated representative acting in that capacity, without being forced to consult with the multiple owners of the unit. Instrumental to this is EPA's proposal to treat all submissions by the designated representative as binding on each owner and operator.

2. Owner/Operator Liability

As a result of the binding authority of the designated representative, subpart B states that the designated representative and the multiple owners and operators of an affected source or affected unit would share liability for any violation by the source or unit of, or any failure by the source or unit to comply with, the requirements of title IV. In certifying an affected source's permit application, the designated representative and the owners and operators of the affected source and of each affected unit at the source would be bound to comply with its terms, and would be responsible for ensuring the affected source's and unit's compliance with those terms.

The definition of "designated representative" in § 72.2 would clarify that the representative must be a natural person. EPA considered whether to allow the designated representative to be a corporate entity rather than a natural person. Such an approach would, however, create a greater risk of disputes regarding representation and was, thus, rejected.

The requirement that the designated representative be a natural person would not result in personal liability on the part of the designated representative in the absence of any criminal wrongdoing. Nor would EPA's proposal interfere with or limit any private indemnification agreements between the designated representative and the source's owners and operators to financially protect the individual representative in the event of a violation. Thus, the designated representative could, for example, be a corporate officer acting in his or her official capacity, risking no more personal liability then would any other officer or operator of the affected source.

In designating a representative to act on their behalf, an affected source's or unit's owners and operators would bind themselves to comply with the terms of any submissions made by the designated representative, and to the actions undertaken by the designated representative, thus, creating shared liability for each and all. This, together with the liability created by the designated representative's certifications, would enable EPA to hold the designated representatives, the owners, and the operators accountable for compliance problems at the affected unit or source, without having to first demonstrate a proper allocation of responsibility among the multiple owners and operators, or between the owners, operators, and the designated representative. The burden of allocating responsibility for noncompliance among multiple owners and operators would be a private matter to be resolved by the interested parties without implicating EPA or any other regulatory authority.

3. Designated Representative, Multiple Unit Permits, and Multiple Source Compliance Options

a. *Multi-unit sources.* Since permits would be issued to each affected source, and affected sources typically will have more than one affected unit, the rule proposes that there be one designated representative certified for each affected source. Thus, even though ownership of multiple units at an affected source might vary, the important programmatic need of dealing with one representative for the affected source would be preserved. The owners and operators of any one affected unit at an affected source would not, however, be liable for violations of the title IV requirements by another affected unit at the same affected source in which they had no ownership or operator interest merely because the two units shared the same designated representative. Multi-unit liability would only be involved to the extent the two units were governed by a multi-unit compliance plan that was violated, or if the violation was of a source requirement (such as the requirement to submit a complete permit application in a timely manner).

b. *Multi-source plans.* As is provided in subparts C and D, the rule proposes, consistent with title IV, to authorize Acid Rain compliance options involving affected units located at more than one affected source. These include substitution plans, Phase I extension plans, reduced utilization plans, and nitrogen oxides averaging plans. For multiple sources electing any such option, each source's permit application and permit would have to include a copy of the cross-referencing compliance plan.

Except in the case of substitution plans and nitrogen oxides averaging plans, where the Act expressly requires common control or ownership of the affected units involved, EPA proposes to not require a single designated representative for purposes of the multi-unit compliance options authorized by subpart D, except when the affected units are located at the same affected source. Instead, the proposal would require that any multi-unit plan involving units located at different sources be jointly certified by the respective designated representatives for each source involved. Such certification would bind the individual owners and operators of all units governed by the plan, which would share responsibility for complying with the plan. The proposed role of the designated representative would make it possible for EPA to approve virtually any variation of multi-unit compliance options, thus, affording sources greater flexibility in achieving compliance.

By requiring that all owners and operators of all the units subject to a multi-unit/multi-source compliance option be bound by their designated representatives' joint submission, and that they share liability for ensuring the compliance of each unit subject to the plan, EPA would be shielded from defenses and disputes between and among multiple owners or operators concerning compliance plans and responsibility for any non-compliance. Without these safeguards, EPA would inevitably have to resolve potentially lengthy disputes between multiple owners or operators concerning their separate liability before issuing a permit or enforcing violations of program requirements. This would make it virtually impossible for EPA to authorize some of the more flexible compliance options (e.g., nitrogen oxides averaging plans which did not specify each individual unit's emissions limitation, but simply imposed a weighted-average emissions limitation for all units covered by the plan). Such disputes would erect unacceptable barriers to EPA's ability to enforce the Act's requirements, which, in turn, would preclude the flexibility proposed to be authorized for approval of multi-unit compliance plans.

4. Certificates of Representation

Subpart B of the proposed rule would require the designated representative to submit a certificate of representation stating, among other things, that he or she was selected by an agreement binding on all the owners and operators of the affected units at the source; and, as provided in section 408(i), that allowances and their proceeds will be deemed to be held for an affected unit according to each owner's respective interest in the unit or pursuant to an agreement entered into by each owner of the unit providing otherwise. In addition, the rule proposes that the terms of the certificate of representation would be deemed to be incorporated into each Acid Rain program submission made by the designated representative. This is essential to establish each element of the designated representative's authority to bind each owner and operator to subsequent submissions.

5. Issues Concerning Representation

a. *Binding agreement of representation.* The Agency considered several approaches concerning what would be minimally necessary for inclusion in a certificate of representation to establish the representative relationship. The rule would require that the designated representative be selected by an agreement binding on all the owners and operators of each affected unit at the affected source. The Agency considered whether to require the "unanimous consent" of the owners and operators for a designated representative to be certified. Although the owners and operators of affected sources would be left free by today's proposal to privately agree on such a unanimity requirement, the Agency does not believe that it would be appropriate to prescribe the decision-making procedures that multiple owners would have to follow in selecting a representative. EPA seeks to avoid any requirement that would inadvertently alter the traditional business dealings within the utility industry. Since a source would not be able to obtain a permit or engage in allowance transactions until it had a designated representative, requiring "unanimous" agreement would give leverage to dissidents that they might not otherwise have, allowing them to force majority owners and operators into unreasonable concessions simply to remove objections. Today's proposal would afford various ownership interests no less protection than they have under existing agreements.

b. *Binding agreement regarding the holding and distribution of allowances—unanimity issue.* Pursuant to section 408(i) of the Act, § 72.20(b)(6) of today's proposal also requires that, in the case of a unit with multiple owners, the designated representative certify that allowances will be deemed to be held, and that the proceeds of allowance transactions will be distributed either (1) in accordance with the respective ownership interests, or (2) if the multiple owners have expressly agreed to a different distribution of allowances by contract, in accordance with that express agreement. Today's proposal specifies that the express contractual agreement providing for a different distribution of allowances and allowance transaction proceeds must be binding on each and every owner of the unit.

EPA seeks comment on whether the rule should also require that the allowance distribution contract be based on a "unanimous" agreement between multiple owners. Although the statute does not expressly provide for such an approach, some commentors believe that one of the statutory purposes of Section 408(i) is to override existing contractual arrangements between owners of a unit to ensure that minority interests are protected. Under that interpretation, existing commercial arrangements regarding how future agreements should be reached would be superseded. For example, a corporate relationship might call for majority vote of the Board of Directors on future agreements, another business relationship might call for arbitration, and yet another might have given all authority of a business's holdings to a general partner, a lessee, or a trustee. In addition, a Federally imposed "unanimity" requirement could impose a potential chilling effect on the designated representative's actions.

c. *Changing the designated representative/objections.* The proposal also stipulates the procedures for changing the designated representative, and that EPA would not become involved in private disputes among multiple owners or operators, nor "freeze" allowance accounts or otherwise stop dealing with the designated representative, even if notified of an objection concerning the actions of the designated representative. This approach would not alter private commercial relationships among multiple owners and operators. Furthermore, aggrieved multiple owners and operators would have adequate protection through their commercial agreements and through the courts, if necessary, to obtain injunctive or monetary relief in the resolution of private ownership disputes. Under the proposed rule the owners and operators could replace a designated representative who was not acting in accordance with the agreement of representation. In addition, if the owners and operators no longer agreed to be represented by the designated representative, and the designated representative knew this, the designated representative would no longer be able to truthfully certify in subsequent submissions to the Agency that he or she was duly authorized. Thus, the Agency does not believe that a unilateral decision by the Agency to freeze allowance accounts is the appropriate remedy to protect the rights of owners.

EPA also believes that freezing allowance accounts would undermine the functioning of the allowance market. The allowance market depends on the ability of third parties to rely on the full effectiveness of the recordation of an allowance transfer. A rule that subjected transfers to the possibility that they might be canceled administratively, even after recordation, would introduce uncertainties. These uncertainties could impair the efficiency of the market by either inhibiting activity or imposing additional transaction costs incurred in an effort to guard against such uncertainties. Second, if the mere filing of an objection forced EPA to suspend recordation of transfers to or from the account, unwarranted objections could introduce disorder into the market or force legitimate designated representatives to make unreasonable concessions to satisfy objections, however unwarranted. EPA, as an environmental regulatory agency, is not in a position to judge the legitimacy of an objection, so the Agency could not effectively guard against unwarranted objections.

The proposal would, however, protect the interests of minority owners. Though designated representatives could be selected by simple majority vote, if that is in accordance with the procedure agreed to by multiple owners and operators for making such decisions, the designated representative would be required to certify that he or she was acting with full authority with every submission to EPA or the permitting authority. If such a certification proved to be untrue—either because an objection from an owner or operator was pending, or because the action violated the rules of the multiple owners and operators agreement for authorizing designated representative actions or for apportioning the allowances among multiple owners—the designated representative would be guilty of making a false certification and risk civil and possibly criminal sanctions under the Act. This affords owners and operators substantial leverage for ensuring that the actions of the designated representative are in accordance with the fiduciary role established by the law.

D. Acid Rain Permit Applications and Compliance Plans

Section 408(a) of the Act specifies that the program be implemented through permits issued to affected sources in accordance with titles IV and V, which in turn provide that it is illegal for a source to operate without a permit. Consistent with other environmental permit programs, such as the National Pollutant Discharge Elimination System (NPDES) under the Clean Water Act, the Resource Conservation and Recovery Act (RCRA), and as provided by title V

of the Act, this rule would place the burden of ensuring that an affected source is permitted on the responsible official for the source, which in the case of the Acid Rain program is the duly certified designated representative. (See discussion of subpart B, above). The Act makes it clear that affected sources are responsible for ensuring compliance with the requirements of the Act; this responsibility does not rest with EPA. (See further discussion, below, concerning permit application shields.)

Subpart C sets forth the basic requirements for permit applications, including the requirement to accompany the application with a proposed compliance plan for each affected unit at the source. In accordance with section 408 of the Act, subpart C provides that permit applications and proposed compliance plans would be binding on the source until the permit was issued. Today's proposal, therefore, would require that the designated representative certify that the source will comply with certain standard conditions contained on the forms pursuant to the Act. In addition, subpart C specifies the basic information concerning the affected source and the affected units at the source that permitting authorities would need in order to write an Acid Rain permit. One essential information requirement would be information identifying the source's utility system and North American Electric Reliability Council (NERC) region or subregion of operation. This information would be necessary to implement the reduced utilization and compensating generation provisions of §§ 72.43 and 72.409 of this part, and sections 408(c)(1)(B) and 403(d) of the Act (See further discussion below).

Another information requirement would be that each unit must specify the most stringent federally enforceable allowable emissions limitation for that unit at the time of application. This limitation would be calculated using the annualization factors included with the National Allowance Data Base proposal (Friday, July 19, 1991, 56 FR 33278). These factors will be promulgated in 40 CFR part 73 at a later date. Subpart C also sets forth the deadlines by which affected sources would be required to apply for initial Acid Rain permits and for Acid Rain permit renewals.

1. Compliance Planning

a. *Compliance options for affected units.* Section 408(b) requires that the compliance option or options chosen for each affected unit at a source be articulated in the proposed compliance plan submitted with the source's application. Thus, § 72.32 of today's proposal requires that, except as noted below for multi-unit compliance options, separate compliance options be included in the compliance plan for each affected unit at the source. Since the sulfur dioxide and nitrogen oxides emissions limitations of the Acid Rain program apply to each affected unit, the rule provides that each affected unit is subject to a separate planning requirement. The specific compliance options available under the program are contained in subpart D of today's proposal. (See, discussion below.) It is important to note, however, that no special compliance planning would be required under 40 CFR part 72 by the Acid Rain program for sources choosing to purchase allowances to cover their unit emissions, to fuel switch, or (except for Phase I extension, repowering, and some of the NO_x options) to install control equipment. Rather, Acid Rain program compliance planning is limited to units seeking special regulatory treatment as provided in subpart D.

b. *Multi-unit compliance options.* The one exception to the separate compliance planning requirement concerns units governed by a multi-unit compliance option approved pursuant to 40 CFR part 72, subpart D. These include substitution plans, reduced utilization/compensating unit plans, Phase I extension plans, nitrogen oxides averaging plans, and plans for units using a common stack. The basis for this proposed exception is that units operating under a multi-unit compliance option have interdependent compliance obligations. (See, further discussion of these and other compliance options at subpart D, below.)

In the case of units operating under any multi-unit compliance plan, exceedances of the emissions limitation governed by the plan (e.g., sulfur dioxide) at any one unit would as a matter of Federal law have to be attributed to all the units governed by the plan. Otherwise, since an individual unit's ability to comply depends on the operations at the other units under the plan, a defense to an offset planning requirement could be raised based on disputes concerning the actions by the other units. Under a substitution plan, for example, an excess emissions situation could be the result of disputes between majority and minority owners concerning the transfer of allowance allocations from the substitution unit's Allowance Tracking System account established under 40 CFR part 73 to the originally affected unit's account. Similarly, a nitrogen oxides averaging plan would not be enforceable without such binding obligations.

Under today's proposal disputes concerning liability between the owners and operators of units covered by a multi-unit plan would not be allowed to delay the offset planning obligation. Because the owners and operators of all units governed by a multi-unit plan would share responsibility compliance with the offset planning obligation, this section would build into the program a self-regulating element that should minimize, if not totally eliminate, such problems. As is noted above in the discussion of subpart B, however, nothing in the rule as proposed would in any way limit private indemnification agreements (i.e., private contractual agreements to reimburse individuals for liability they incur in their official capacity in an enforcement action). Such agreements could not, however, be raised as a defense in any Federal enforcement action.

c. *Using multiple compliance options.* The rule as proposed would allow affected units to rely on one or more of the compliance options provided for in Subpart D of the proposed rule, to meet their SO_2 and NO_x emissions reduction requirements. If one or more of these options were chosen, the permit application would have to include the additional information requirements for that option set forth in Subpart D of today's proposal.

d. *Conditional approval of compliance options.* In order to afford affected sources maximum flexibility in compliance planning, and to obviate the need and burden to the source of subsequent permit revisions, the designated representative for a source could seek conditional approval, in accordance with subpart D, of several compliance options. Thereafter, the designated representative would have to notify the Agency of the source's decision to "activate" any one conditionally approved compliance option. In some instances this flexibility may be limited by deadlines or other requirements due to the nature of the option. The reader is referred to the specific sections of today's preamble discussing the compliance options in subpart D to see what restrictions would apply.

2. Mandatory Use of Forms/Paperwork Reduction Act

The Agency believes that it is important to minimize the imposition of duplicative or inconsistent information requirements on sources. Today's proposal would do so through the use of standardized forms and by codifying certain critical information concerning existing sources in the Appendices. (See.

e.g., appendices A, B and C). It is also important, however, to ensure that all necessary permit information and enforceable requirements be specified in one consolidated format, in order to expedite permit processing, to afford meaningful public review of proposed permit actions, and to ensure compliance. Ensuring that permit applications and proposed compliance plans have complete information is particularly important to the Acid Rain program since, pursuant to sections 408(c)(1)(A) and 408(d)(3) of the Act, an Acid Rain permit application and proposed compliance plan submitted in accordance with title IV is binding on the source until superseded by a permit and approved compliance plan. Today's proposal would, thus, require permit applications to include certain information which EPA could obtain by other methods. In balancing these competing interests, the Agency has determined that the costs to sources of providing certain critical information that might be otherwise available are outweighed by the benefits of having all of the information about a source necessary to write a permit and ensure compliance prior to a permit's effective date provided by the applicant in one document. The Agency requests comment on this approach, and suggestions on whether the Agency could ensure clear articulation of all applicable requirements before the permit is in effect, without requiring their inclusion on the application forms.

The Agency's proposal to require that all applications be submitted on EPA-issued standard forms, and that States and local permitting agencies use these forms when issuing Acid Rain permits for Phase II will also help to ensure national consistency in information requirements for Acid Rain permit applications. Requiring standard forms, whether the permitting authority is EPA, a State, or a local agency, would ensure parity, and, thus, help promote a national allowance market. Nationwide use of standard forms would reduce the administrative burden on affected sources and permitting authorities associated with permitting. Utilities with sources located in more than one State would not have to complete different, and possibly conflicting, applications for each source. In addition, the use of standardized forms would facilitate the burden on States of developing an Acid Rain permitting program, and help ensure against some States inadvertently having more (or less) extensive informational requirements than others.

Ensuring that utilities in different States will have the same permit application requirements and burden should also facilitate a national allowance market. If, for example, one State required considerably more information about the source or more detailed compliance plans prior to issuing an Acid Rain permit than did another State, the source might encounter delays in obtaining permit approval or have greater difficulty making demonstrations. This could add to the source's incremental "cost" of permitting and of obtaining allowances. While costs of compliance may vary from source to source, thus affecting the individual value of allowances, the Agency believes that variations in these costs on the basis of who the permitting authority is, should be avoided to the extent possible. The Agency requests comment on the use of standardized forms nationwide.

EPA is also developing the Acid Rain permit program with a view toward eventual electronic reporting for permit applications and compliance plans for Phase II. Consistent with current EPA policy, set forth at 55 FR 31030 (July 30, 1990), the forms proposed today have been developed in a way that is compatible with ANSI-X12, a computer-reporting system which is in widespread use throughout the United States for commercial reporting of information. The Agency plans to work with industry and States in developing specifications for compatible electronic reporting of Acid Rain permit applications and compliance plans, and in developing user-friendly software packages to facilitate this reporting. Electronic reporting of applications and compliance plans would not be mandatory, consistent with Agency policy, but would be recommended where feasible. The Agency believes such reporting would be particularly helpful in establishing a truly dynamic permitting and allowance data system. The Agency requests comment on the use of electronic reporting for permit applications and compliance plans.

3. Relationship of Acid Rain Permits to Emissions Monitoring Requirements

a. *Monitoring plans and certifications.* The permit application for the source would have to indicate how each affected unit at the source would meet its emissions monitoring requirements under section 412 of the Act and 40 CFR part 75. The Agency is, consequently, proposing in the emissions monitoring rules at 40 CFR part 75 that the designated representative for each Phase I affected source submit a proposed monitoring plan to EPA for approval for each affected unit at the source, prior to or concurrent with the source's permit application. Section 412 of the Act does not, however, require that the emissions monitoring system verification test results for Phase I units be submitted by the February, 1993 Phase I permit application deadline. Thus, the rule proposes that timely submission of the monitor verification test results and monitor certification be an enforceable permit requirement, and that certifications would be incorporated into the permit upon notification of the designated representative by the Administrator.

b. *Alternative monitoring applications.* Unless a source had obtained Agency approval under 40 CFR part 75 of an alternative monitoring system by the time a permit application was submitted, the permit would be issued requiring compliance with the CEMS requirements of 40 CFR part 75. In the event an alternative monitoring system was approved by the Agency after permit issuance, the permit would have to be revised in accordance with subpart J to authorize use of such alternative. The Agency proposes that permits be revised using the administrative amendment procedure specified in § 72.303 of today's proposal to include alternative emissions monitoring requirements that have been reviewed and approved by the Administrator under 40 CFR part 75. This is appropriate since 40 CFR part 75 provides that such actions by the Administrator would be subject to an opportunity for public comment. Affording any further opportunity for public comment for the sole purpose of incorporating a properly approved emissions monitoring requirement into the permit would, thus, be redundant. Moreover, the administrative amendment procedure includes subsequent public notice of the revision. The Agency requests comment on this approach.

c. *Common stack monitors.* Section 72.50 specifies the requirements for common stack plans. The Agency proposes that units sharing a common stack shall so specify in the monitoring plan submitted with their permit application, and shall either monitor emissions independently or shall comply with the requirements in that section.

d. *New units.* The Agency proposes that all existing Phase II units must have monitors operational and certified by January 1, 1995. Any new unit that becomes affected between January 1, 1995 and December 31, 1999 must have monitors operational and certified by

the effective date of the plan under which it becomes a Phase I affected unit.

E. Acid Rain Compliance Options

A fundamental feature of the Acid Rain program is the flexibility provided in the Act for sources to choose cost effective means of complying with the mandated SO_2 and NO_x emissions reductions requirements. Sections 404, 405, 407, 408, 409, and 410 of the Act provide various compliance options by which an affected unit may obtain special relief to assist in its efforts to comply with its emissions limitations under the program. Section 408(b) specifies that the option or options chosen for each affected unit must be articulated in the proposed compliance plan submitted with the permit application for the source. It is important to note, however, that no special compliance planning would be required by the Acid Rain program for sources choosing to fuel switch, or (except for Phase I extension, repowering, and some of the NO_x options) to install control equipment. Rather, Acid Rain program compliance planning is limited to affected units seeking special regulatory treatment as provided in subpart D.

Subpart D describes the proposed requirements for each of the compliance options specifically authorized by the Act. As provided in subpart C each permit application would contain at least a standard permit application form specifying information and applicable standard requirements for each affected unit at an affected source. These would include the standard compliance requirement, i.e., a certification for each affected unit that it will meet the applicable emissions limitation requirements of the program in a timely manner, including a certification that for purposes of SO_2 compliance the affected unit will hold enough allowances in its Allowance Tracking System compliance subaccount to cover its SO_2 emissions for the year. (For NO_x, the emissions limitation would be the applicable limitation specified in 40 CFR part 76, and each permit application would have to identify the type of boiler involved so that the applicable 40 CFR part 76 NO_x limitation would be clear).

If an affected unit planned to comply with the Acid Rain program SO_2 or NO_x standard compliance requirements without any special exceptions, a simple check-box on the permit application would indicate this choice. However, for affected units relying on one or more of the compliance options for SO_2 or NO_x authorized by the Act, a proposed compliance plan using the appropriate form for the option or options chosen would have to be included with the permit application package. Upon approval, the unit-specific compliance plans would be attached to the permit for that source and, depending on the option approved, would modify the program's standard requirements. The Agency requests comments, however, on whether it would be more appropriate to specify the terms of all unit-specific compliance plans in the permit as alternative operating scenarios, or whether the approved compliance plans should as proposed today be attached and incorporated into the permit by reference. In either case, the legally applicable requirements the source would be subject to would be the same. For example, in either case, the source would be able to activate a conditionally approved compliance option (or operating scenario) by providing notice to the permitting authority, using the administrative permit amendment procedures of § 72.303, as discussed below. However, by specifying the terms of the "operating scenarios" in the permit, all of the requirements applicable to a source would be articulated in one document, as compared to the two-document approach proposed today. Under today's proposal, however, those requirements more likely to undergo numerous revisions during the course of a permit's term, i.e., the unit-specific compliance options, will be contained in the separate compliance plan proposed by the source, and approved by the permitting authority and incorporated by reference into the permit.

The permit revision procedures proposed in Subpart J of today's proposal, as they apply to compliance plans, are also designed to increase the flexibility for the compliance option provisions of the Act. A source would be able to conditionally propose several compliance options for each affected unit for approval when it submitted its permit application. A conditionally approved option would not become effective unless activated by the source. Activation of an option that was previously conditionally approved could, thus, be accomplished by a simple notice process as an administrative amendment to the permit. Because the various compliance options are subject to specific statutory requirements and limitations, today's proposal would specify rules for activating options as appropriate and necessary. Any compliance option not included in the original permit application, which was proposed after permit issuance, could be added by revising the permit pursuant to subpart J.

1. Multi-Unit Requirements

The rule proposes that the permitting authority can approve multi-unit compliance plans where the units are located at different sources. In such cases, the designated representative of each source would have to certify the compliance plan, a copy of which would have to be included in the permit application for each source. This provision is intended to provide utilities with flexibility in determining least-cost methods of compliance, and to allow compliance plans that are consistent, for example, with pre-existing power pooling arrangements. Restricting compliance plans to one source would greatly interfere with this flexibility. The Agency requests comments on this approach.

2. Phase I Substitution Plans

Subsections 404 (b) and (c) of the Act authorize any source with a Phase I appendix A affected unit to propose in its Acid Rain compliance plan a reassignment of the affected unit's Phase I sulfur dioxide emissions reduction requirements, in whole or in part, to one or more existing Phase II, appendix B units. The designated substitution unit would, in turn, become a Phase I unit. The intent of this provision is to give any appendix A Phase I unit the flexibility to reassign its Phase I emissions reductions obligations by allowing an appendix B unit to achieve reductions in its place, above and beyond what the Phase II unit would otherwise be required to achieve. It also would provide Phase II appendix B units the opportunity to participate in the Acid Rain program allowance system early, and to benefit from the economies associated with the allocation and banking of allowances.

The following example illustrates how a substitution plan might work: A Phase I unit emits 100,000 tons of SO_2 a year, but is only entitled to receive 50,000 allowances to cover its annual SO_2 emissions. It, therefore, needs 50,000 tons of extra allowances. Under a substitution plan, a utility may meet its allowance obligations by reducing emissions from one or more appendix B units by a total of 50,000 tons from its 1985 level of emissions and transfer the appendix B unit's allowances to the appendix A unit.

(a) *Applicable units/exclusions.* Only existing Phase II units (listed in appendix B) would be eligible to participate in substitution plans with Phase I units. This requirement would

rule out units that are not affected units under title IV and new units. The Agency considered whether sources not affected under title IV should be allowed to become substitution units. The Agency believes that no added flexibility would be achieved by allowing sources not subject to title IV to be designated as substitution units since such sources would be able to participate in the allowance program as opt-in units pursuant to section 410 of the Act and 40 CFR part 74. In addition, such an interpretation would undermine the intent of Congress to encourage early reductions at existing Phase II units under section 404 (b) and (c), as well as the specific limitations imposed by Congress on sources not otherwise governed by title IV which elect to participate in the Acid Rain allowance system under section 410 of the Act. For example, section 410 opt-in sources may not transfer allowances freed up by reducing utilization below their baseline.

The Agency also proposes to exclude new units from the substitution provision because, with limited exceptions, the Act prohibits the allocation of allowances to new units. Thus, a rule authorizing allocations of allowances to new units under substitution plans would dilute the emissions reductions the Act intended to be achieved during Phase I. Nor do new units have the historical operating data to calculate the reductions that would be required under a substitution plan. Such units were clearly not intended to be eligible to participate in the Acid Rain program under the substitution provision.

(b) *"Common control" requirement.* The proposed requirement in § 72.41(a) that the substitution unit be under the "common control" of the same designated representative as the appendix A unit for which the proposed plan is submitted is based on the statutory requirement that the units be under the control of the same "owner or operator". This is an exception to the general rule discussed above that units at more than one source could be designated in a single compliance plan signed by multiple designated representatives. The statutory language for substitution plans would prohibit this flexibility. By proposing that a single designated representative be deemed to fulfill the requirement of "common owner or operator", the Agency seeks to allow greater flexibility for sources while at the same time ensuring that the statutory concern regarding accountability will be met. As discussed above under subpart B, an alternative reading of the statutory language would require that the units be under the control of the same owner or operator, and would hold that a common designated representative alone is inadequate unless that person is also an owner or operator. The Agency solicits comments on the approach taken in the proposed regulation, and on the alternative reading of the statute.

Section 72.41(e) specifies the requirements and prohibitions that would apply to substitution plans, including the requirement that the designated representative and the owners and operators of the original and substitution unit will share the responsibility for ensuring compliance with the plan by each unit, and liability for any violation. The basis for this provision is discussed in the general section on compliance plans and in the section on designated representatives.

(c) *Conditions of plan.* The Act requires that the substitution plan ensure that the same or greater emissions reductions be achieved as would have been required to be achieved without the plan. The rule proposes step-by-step instructions concerning what would be needed in a substitution plan demonstration to meet this requirement. These proposed demonstration requirements are based on the provisions of section 404(b) of the Act concerning what is required to be included in each proposed substitution plan. The proposal also specifies that the Administrator would allocate allowances to the appendix A and substitution unit(s) in accordance with the approved substitution plan and that, thereafter, only the standard quarterly and end-of-year compliance certification reports would be necessary. The proposed reporting requirements have been kept to a minimum because the Agency believes that, once a substitution plan is approved and the appropriate number of allowances are allocated for the year, the integrity of the plan is ensured.

Consistent with section 404(b)(5), today's proposal assumes that when determining the reductions that would have been achieved without the substitution plan, the reductions that would have occurred at the appendix A unit must be considered, as well as the reductions that would have been required of the appendix B unit where its federally enforceable applicable SO_2 emissions limitation (e.g., SIP limit) was made more stringent after 1985. Voluntary reductions at the appendix B unit above and beyond what it was required to do under applicable federally enforceable law would not be included in the calculation of reductions without the plan, since that would unnecessarily penalize and discourage early reductions. The appendix A unit's required reductions would be calculated based on the difference between the unit's 1985 emissions rate multiplied by the unit's baseline and the unit's basic allowance allocations for Phase I (as authorized by Table A of the Act or as adjusted pursuant to section 403. See, appendix A). The appendix B unit's reductions would be equal to the difference between its baseline multiplied by the lesser of its actual or allowable 1985 emissions rate and its baseline multiplied by the more stringent allowable rate at the time it was designated for substitution.

Alternatively, the Agency asks for comment as to whether the reductions that would have been achieved by the substitution unit in the absence of the plan should be deemed to be zero. Such an approach would be based on the fact that appendix B units are not required by title IV to achieve emissions reductions during Phase I. It could, thus, be argued that the rule, as proposed, would increase the overall Phase I reductions contemplated by the Act.

The Agency considered whether to calculate required reductions and allowance allocations for the substitute unit based on the substitution unit's current utilization and emissions rather than on the unit's baseline (i.e., 1985 through 1987) utilization and emissions. Such an approach would provide an additional incentive for substitution plans by accounting for growth. The Agency decided against this approach, however, for several reasons. First, neither section 404 (b) or (c) authorize growth credits. Second, the statutory authorities for calculating allowance allocations for Phase II are based on each unit's baseline utilization. Similarly, the only other provision under which Phase II units can become affected units during Phase I, section 408(c)(1)(B) of the Act (reduced utilization), does not authorize allocations for growth allowances. Thus, even though the program's 8.95 million allowance cap does not begin during Phase I, it is apparent that Congress intended the substitution provisions to encourage and reward early controls, not to be used as a vehicle for inflating the number of allowances available on the market during Phase I of the program.

(d) *Termination of substitution plans.* The proposed rule allows units subject to substitution plans to terminate such plans and to de-designate substitution units in a plan. As a pre-condition of

such termination or de-designation, the affected substitution units must surrender allowances equal to those allocated pursuant to the substitution plan. This is to ensure that future-year allowances, equal to those allocated to the appendix A and substitution unit under the presumption that the substitution unit would continue to be affected for the remainder of the Phase, cannot be used in future years when the designated substitution unit is no longer affected and no longer making verified emissions reductions. To effectuate the surrender of such allowances, the rule requires that before the substitution plan can be terminated or a substitution unit designated, the substitution unit's Allowance Tracking System subaccounts must include allowances equivalent in number and compliance use date to those allocated to the substitution or original Phase I unit (above the original unit's basic allocations) pursuant to the substitution plan for the remaining years of Phase I. When the plan is terminated, the Agency will deduct the allowances from the substitution unit's account.

3. Phase I Extension Plans

Section 72.42 of the rule would implement the authority in section 404(d) of the Act, which provides that Phase I units may apply for a two-year extension of the Phase I compliance deadline of January 1, 1995, provided that the units install 90% sulfur dioxide removal technology or transfer their emissions reduction obligations to a unit or units that install such technology. (See, § 72.2 for definitions of "qualifying Phase I technology", "transfer unit" and "control unit".) The Act provides that applications for Phase I extensions be acted upon by the Administrator in the "order of receipt". A limited reserve of up to 3.5 million allowances is authorized in title IV to provide units that apply early enough and are granted Phase I extensions the extra allowances they will need to cover their sulfur dioxide emissions during the extension period.[2] The unit which installs the 90% control technology ("control unit") would also be eligible for additional allowance awards from this reserve for the three years after the extension period (1997–1999). These additional allowances would be provided to the extent the control technology reduces emissions at the unit beyond the standard Phase II emissions limitation of 1.2 lbs/mmBtu. (See, section 404(d)(4)(c))

Section 404(d) was included in the Act to reduce the impact of the Acid Rain emissions reduction program on employment in high-sulfur coal mining communities, and to defray the compliance costs and consequent electricity rate increases that would otherwise be charged by some of the Phase I utilities currently using high-sulfur coal (See statement of Senator Baucus, Congressional Record, October 27, 1990, S 16981). The Agency considered these fundamental intentions in its interpretation of the final statutory language, and has interpreted section 404(d) to the extent consistent with the statutory authority, to ensure that the reserve is not unnecessarily depleted. In addition, as is discussed further below, the Agency is proposing procedures to expedite the conditional award of allowances from the reserve in order to maximize the opportunity for sources to participate in the program.

(a.) *Applicable units.* Section 72.42(a) of the proposed rule states that the Phase I extension option may apply to: (1) All appendix A units; and (2) Appendix B units used as control units and designated as affected units during Phase I as a result of their inclusion in either a substitution plan or a reduced utilization plan.

Consistent with the Act, the Agency proposes that new units not be eligible for inclusion in Phase I extension plans. New units would be required to meet strict SO_2 control requirements under other provisions of the Act. The Agency believes that allowing new units to benefit from achieving the level of control they would be required by law to meet anyway would deplete the reserve at the expense of Phase I affected units, and would be inconsistent with the intent of the Phase I extension provisions. The Agency also proposes not to allow opt-in units to apply for extension allowances for similar reasons, since they are not required to become affected units during Phase I.

The Agency has interpreted the statutory requirement in section 404(d)(1) that the control unit "employ" a qualifying Phase I technology to mean that any Phase I Appendix A unit that installs and operates qualifying technology on or after enactment up until the end of the extension period on December 31, 1996, can apply for extension allowances. A unit that installed qualifying Phase I technology before enactment would not be eligible to apply for the extension, since sources installing controls before enactment clearly did not do so to comply with title IV. Expanding the potential pool of applicants in this way would deplete the reserve and restrict the number of controlled units that would be granted extensions.

EPA considered whether to restrict eligibility for reserve allowances to only those units installing qualifying technology during the 1995 and 1996 extension period. This interpretation was rejected because it would penalize those utilities that controlled their units early. Moreover, had Congress intended to fully exclude units controlled before 1995, they could have clearly stated as much.

b. *Transfer unit limitations.* The rule proposes conditions which would govern the relationship between a unit which installs qualifying Phase I control technology and Appendix A units which transfer their emissions reduction obligations to that unit. One condition would prohibit the control unit from being oversubscribed. In this way, the appendix A transfer units could not receive more extension allowances during 1995 and 1996 than the tonnage of reductions that would be achieved by the control unit below its basic allowance allocation by installing 90% control technology. For example, if a control unit would receive 50,000 allowances during each year of Phase I and 90% control of the unit would reduce its emissions to 10,000 tons per year, no more than 40,000 allowances could be allocated from the reserve to transfer unit(s) for 1995 and 1996 (i.e., the difference between the control unit's basic allocations and the unit's emissions assuming 90% control), even if the transfer unit(s) needed more allowances to cover actual emissions during the extension period. This limitation is to ensure that the reserve would not be depleted by units that were not installing controls. The Agency proposes this requirement because, without it, a utility could draw an unlimited number of allowances from the reserve in 1995 and 1996. The proposal also prohibits transfer units from transferring their same emissions reduction obligations to more than one control unit. Transfer units may be changed at any time prior to January 1, 1995, provided that no additional allowances would be available under a plan as a result of such a revision.

c. *Control unit limitations.* The Agency proposes that each application for a Phase I extension may specify more than one control unit, provided that all control units included in the

[2] A unit granted an "extension" under section 404(d) is not exempted by title IV from the requirement to prevent emissions of sulfur dioxide in excess of the allowances held in the unit's Allowance Tracking System account. Section 404(d) is, thus, better understood as authorizing a higher sulfur dioxide emissions limitation (and more allowances) for a two-year period, rather than an "extension" of the compliance date.

proposed plan are located at the same source. Allowing control units from more than one source to be included in one application would tend to give the largest utilities an undue advantage to draw-down large numbers of allowances from the reserve should that application be treated ahead of others. Requiring a separate application for each source would, thus, help ensure a more equitable distribution of the reserve. There are, however, significant reasons for allowing applications with more than one control unit at a source. For example, a source may be planning to treat the emissions from all its units with one Qualifying Phase I Technology. Such a source might only be able to justify continued use of high sulfur coal if all its units had high efficiency controls installed. The Agency requests comment on this aspect of today's proposal. Control units may be dropped from a plan at any time prior to 1995. New control units could not, however, be added or substituted in.

d. *Contents of proposed Phase I extension plan.* Each proposed Phase I Extension plan would include a copy of an executed contract for the design and construction of qualifying Phase I technology as required in section 404(d)(1)(B) of the Act. The Agency considered whether to provide an exemption from this requirement for units located in States where state law requires the unit to install a scrubber. The Agency decided not to allow such an exemption for several reasons. First, the statutory language explicitly requires a contract. Second, such an exemption could provide certain units with an undue advantage in obtaining the Phase I Extension reserve allowances because they would not be delayed in submitting an application by the requirement to negotiate a binding contract. Finally, the Agency does not want to encourage such special interest legislation.

In § 72.42(e) the Agency proposes specifications for the two parameters used to determine the number of allowances allocated to each Phase I Extension unit from the Phase I extension reserve. The average annual emissions (in tons per year) for calendar years 1988 and 1989 as required by section 404(d)(4) (A) and (B) of the Act would be calculated using information reported on EIA form 767 and as listed in Appendices A and B of this part for those years or the most stringent federally enforceable allowable emissions limitation for those years, whichever is less.[3] The most stringent federally enforceable allowable emissions limitation would be calculated using the annualization factors specified in the National Allowance Data Base proposal (56 FR 33278, Friday, July 19, 1991). (These will be published in final at 40 CFR part 73 at a later date.)

Section 72.42(e) also provides that projected 1995 and 1996 emissions would be calculated using (A) projected utilization as reported on EIA form 767 filed in the year in which the Phase I extension is made, and (B) the lesser of the most stringent federally enforceable emissions limitation or the unit's actual projected emissions at the time of application.

The Agency considered whether to allow a procedure for sources to petition for adjustments of these information points, but believes that such a procedure is not warranted for several reasons. First, the Phase I Extension is voluntary. If a utility finds that it is not favorable to apply for a Phase I Extension, it can chose another compliance option. Second, the information is historical, actual data reported by the utility itself and the statute does not provide for adjustment. (Cf. section 403). Third, the Agency is attempting to respond to industry's need for certainty at an early date regarding allocation of allowances from the Phase I Extension reserve. Allowing an opportunity for adjustments to be made to essential historical data would delay certainty. However, some industry concern was raised about the need for an adjustment to the emissions data for narrowly defined situations such as a forced outage during 1988 and 1989. The Agency requests comment on the appropriateness of allowing an adjustment in the limited situations where a forced outage occurred.

To implement section 404(d)(4)(A) and (B) of the Act, today's proposal allows for awards of Phase I Extension reserve allowances to control units in 1995 and 1996 based on each unit's projected uncontrolled emissions for those years. This is because the authority to award reserve allowances for the extension period is based on the assumption that such allowances are needed to cover operations at control units before the controls are installed. However, under today's proposal even if a control unit had an operational scrubber in place by 1995, it would receive reserve allowances in 1995 and 1996 as if it were not scrubbing. An alternative interpretation of the statutory language of section 404(d)(4)(A) and (B) would allow awards of reserve allowances to each control unit based on its projected uncontrolled 1995 emissions only if the scrubber was not actually operational in 1995. If the scrubber were operational, the unit would receive allowances from the reserve based on the absolute (i.e., positive) difference between 2.5 lbs/mmBtu x baseline divided by 2000) and the unit's projected controlled emissions (at 90%). The Agency requests comment on which of these two interpretations would be most appropriate to adopt.

e. *90% control technology demonstrations.* EPA considered several methods for demonstrating a technology's capability to achieve 90% control for SO_2. For example, EPA considered whether a designated representative should provide detailed information on technical parameters of the equipment. Ultimately, however, the Agency believes that a basic demonstration of the capabilities of the technology is adequate and will ensure more expeditious processing of extension applications. This is because at an estimated market price of $500 an allowance, sources will have sufficient incentive to achieve, if not exceed, 90% control efficiency. Thus, today's proposal would require that the plan include a basic description of the technology, the executed design engineering and construction contract for the unit installing the technology, and a vendor guarantee that the technology is designed to achieve or exceed 90% control efficiency at expected ranges of fuel type and operating conditions.

There are several reasons for relying on this approach. First, section 404(d)(7) provides that after January 1, 1997 an allowance is required to be deducted from each transfer or control unit's Acid Rain Allowance Tracking System compliance subaccount for each ton of SO_2 emitted by the unit in excess of the annual tonnage limitation specified in their extension plan. This deduction of allowances is in addition to any excess emissions offsets required under section 411. (See, discussion of 40 CFR part 77, below.) The Agency's interpretation of this provision is that the annual tonnage limitation specified in a Phase I extension plan would not only determine the allowances which would be awarded to the unit from the reserve, but would represent a cap on the

[3] If the data for 1988 or 1989 tons of SO_2 is missing from Appendix A or B (missing data is represented by a "-", not by a "0"), for any unit, the EIA Form 767 may be refiled by the source for the missing year. EPA will accept any such data from EIA. If the unit is not covered by Form 767, EPA will calculate the tons per year for 1988 or 1989 upon receipt of adequate documentation. EPA invites comment on how to calculate missing data.

allowable annual tons of SO_2 which could be emitted by the named control and transfer units. Thus, each unit subject to a Phase I extension plan would, pursuant to § 72.42(g), have allowances deducted to the extent it exceeded the limitation specified in its plan even if it had allowances in its Allowance Tracking System account to cover all its emissions for the year. EPA believes that Congress intended this cap on Phase I extension units to serve as an assurance that the 90% control requirement would be met, and that both transfer and control units would abide by the annual tonnage limitations specified in the Phase I extension plan.

The Agency proposes that the 90% control obligation would apply through the end of Phase I. Utilities will receive substantial financial benefits from the bonus allowances allocated for a Phase I extension based upon the annual tonnage limitations specified in the extension plans. Because the Phase I extension reserve may be oversubscribed, the award of extension allowances to one unit is likely to mean that another otherwise eligible unit will not receive any extension allowances. Thus, as a matter of equity, it would be appropriate that units be required to maintain the levels of SO_2 control and emissions reductions upon which their bonus allowance allocations were based past Phase I.

The Agency has included in today's proposal a requirement that sources demonstrate achievement of 90% control through a start-up, and an annual performance test during each year of Phase I. This procedure would verify whether the limits specified in the plan are actually the result of the unit's use of 90% control technology. The test methodology for making the demonstration is proposed today in 40 CFR part 75. (It should be noted that the test methodology specified in 40 CFR part 75 would only apply to post-combustion control technologies. It would not apply to units that achieved 90% control with pre-combustion and combustion technologies, such as coal cleaning or repowering technologies. In such instances the Agency proposes that sources be required to demonstrate 90% control using a methodology proposed by the source and approved by the Administrator on a case-by-case basis. The unit would not obtain the conditionally allocated reserve allowances after it commenced operation of the controls, until 90% removal efficiency was demonstrated by a start-up test. Thereafter, if the annual performance test did not demonstrate 90% removal efficiency, the conditionally allocated reserve allowances for that year would be withheld from the units Allowance Tracking System account. The Agency requests comment on the 90% performance test provision. In particular, the Agency requests comment on whether the annual test should be a 30-day test which, if failed in the first instance could be repeated until 90% control can be demonstrated, or whether control units should, as proposed today, be required to demonstrate 90% control on an annual average basis, using continuous inlet monitor data collected throughout the year.

f. *Determining "order of receipt"—Early ranking procedure.* Section 72.42(c) and subpart L of today's proposal (discussed further below) addresses the statutory mandate that submissions for Phase I extensions be acted on by the Administrator "in order of receipt", as well as the need of the regulated community to know whether they will be eligible for extension allowances as early as possible. Because of the economic benefits a source would derive from a Phase I extension, the allowance reserve of up to 3.5 million tons is expected to be oversubscribed. The Agency consequently believes that many sources are likely to apply for the extension allowances on the first day for submitting applications authorized by the rule. It may, therefore, be difficult to determine the "order of receipt" by relying exclusively on the U.S. postal system. Because of the problems inherent in implementing this provision, the Agency proposes a procedure at subpart L of the rule allowing applicants the option of seeking early rankings of Phase I Extension applications, conditioned on submission by applicants of complete and approvable permit applications by the section 408 Phase I deadline of February 15, 1993. The Early Ranking procedure is contained in a separate subpart of today's proposal in order to expedite rulemaking. (The Agency believes that going to an expedited final rulemaking on critical provisions, i.e., § 72.42, subparts A, B, and L, may be possible if no significant adverse comment is received on those portions of the rule.) The Agency is proposing the Early Ranking procedure in order to provide sources with a reasonable idea, at an early date, of whether they will be likely to qualify for and receive allowances under § 72.42 for Phase I extensions. Information available to EPA indicates that it may take up to three years to design and install 90% control technology. Utilities, thus, need this assurance as early as possible in order to be able to install controls at their Phase I units before January 1, 1997.

In the event comment on this and other provisions of today's proposal central to Phase I extensions (e.g., subparts A, B, L and substitution plans) is favorable, the Agency proposes to accelerate a portion of this rulemaking to implement the early ranking procedure as soon as possible. Significant adverse comment would make this less likely.

g. *Prohibition on termination of approved Phase I extension plans.* Generally today's proposal authorizes sources to terminate compliance options using the subpart J permit revision procedures. This general flexibility would not, however, apply in the case of approved Phase I Extension plans. The Agency believes that due to the competition for the limited Phase I Extension allowance reserve, sources should be subject to a firm requirement to go forward with installation of qualifying Phase I control technology once their proposed plan is approved. Sources may, however, elect to withdraw their plan before it is approved by the Administrator since they would not have benefitted from the award of any reserve allowances.

4. Phase I Reduced Utilization Plans and Under-utilization Accounting Requirements

a. *Background.* Utilities with units subject to emissions limitations in Phase I of the Acid Rain program may choose among a number of compliance strategies. One such strategy is to reduce utilization at higher emitting units, and to replace this generation through increased utilization of low-emitting units.[4] In enacting title IV, however, Congress recognized that during Phase I of the Acid Rain program, reductions in emissions attributable to a decrease in utilization of Phase I affected units below their baseline could prevent full achievement of expected emissions reductions if the generation were shifted to non-affected units.[5] This is because such load shifting would result in a decrease in emissions and concomitant creation of excess allowances at the Phase I unit, despite the fact that there was an emissions

[4] The inherent fungibility of allowances and emissions reflects Congress' intent to enable utilities to utilize least-emissions dispatching procedures, in order to minimize their compliance costs. (See, Sen. Rept. No. 228, 101st Cong., 1st Sess., pp. 316, 319 (1989), House Rept. No. 490, 101st Cong., 2nd Sess. p. 373 (1990).)

[5] E.g. Phase II appendix B or new units.

increase at the non-affected unit providing compensating generation.

At the same time, Congress recognized that in order to ensure electric reliability, it was necessary to accommodate temporary changes in emissions (and shifts in utilization) resulting from decisions related to normal dispatching procedures and responses to emergencies. Because such load shifting between affected and non-affected units, whether planned or unplanned, could cut the actual aggregate emissions reductions expected during Phase I by as much as 50% a year, the Act includes two provisions, section 408(c)(1)(B) and section 403(d), to address these related but distinct situations. Both provisions give EPA the authority to require an allowance accounting for increases in emissions at otherwise non-affected units providing compensating generation.

Throughout the rule and preamble the term "under-utilization" is used to refer to any decrease in utilization at a Phase I unit below its baseline.[6] The term "reduced utilization" is used to refer only to under-utilization subject to the planning requirements of section 408(c)(1)(B) of the Act.

(1) Section 408(c)(1)(B). Under section 408(c)(1)(B), the designated representative, owners, and operators of any Phase I affected unit planning to achieve Phase I emissions limitation requirements by reducing the unit's utilization below its baseline or shutting the unit down, and shifting generation to a unit that is not otherwise affected during Phase I, are required to designate the otherwise unaffected unit as a Phase I compensating unit. The designated compensating unit becomes a Phase I affected unit subject to the Phase I emissions limitation, permitting, monitoring and excess emissions requirements of the Act. In addition, the designated compensating unit is allocated allowances by the Administrator approximately equal to its 1985 emissions, pursuant to a formula set out in section 408(c)(1)(B).[7]

In this way, the Act allows shifts in generation from a Phase I unit to a designated compensating unit, while ensuring that emissions increases at the compensating unit are accounted for in the allowance system. In addition, all allowance savings resulting from the reduced utilization at the Phase I unit can be banked by the source, since these unused allowances will correspond to actual net reductions in SO_2 emissions for the year.

(2) Section 403(d). Section 403(d)(2) provides, in relevant part:

In order to insure electric reliability, regulations shall not prohibit or affect temporary increases and decreases in emissions within utility systems, power pools, or utilities entering into allowance pool agreements, that result from their operations, including emergencies and central dispatch, and such temporary emissions increases and decreases shall not require transfer of allowances among units nor shall it require recordation.

This language reflects Congressional intent to enable utilities to integrate compliance with their emissions limitation obligations with the normal operation of the nation's electric generation dispatch system. It specifically precludes EPA from issuing regulations that might hinder the ability of utilities to vary the utilization of individual units during the course of a year for energy reliability reasons according to traditional utility electricity dispatching practices.

Notwithstanding this goal of regulatory neutrality, however, section 403(d)(2) also contains a requirement that utilities compensate at the end of the year for emissions resulting from generation load-shifting due to dispatching, including shifts from affected to non-affected units. Section 403(d)(2) goes on to provide, in relevant part, that:

* * * [T]he total tonnage of emissions in any calendar year (calculated at the end thereof) from all units in such a utility system, power pool, or allowance pool agreements shall not exceed the total allowances for such units for the calendar year concerned.

In addition, section 403(d)(1) requires EPA to promulgate regulations that provide for the "orderly and competitive functioning of the allowance system." EPA believes that an essential element of an "orderly and competitive" allowance system is that utilities not be allowed to bank allowances in the absence of actual reductions in emissions.

A system that permitted the banking of allowances without ensuring that corresponding emissions reductions took place in the year the allowances were banked would defeat the statutory intent to use allowances as the backbone of a national compliance system. While some banked allowances would reflect costs actually incurred by a utility to achieve actual emissions reductions, others would be banked notwithstanding the fact that actual emissions reductions had not been paid for or achieved. Thus, although cost-effective utility operations are encouraged, subsections (d) (1) and (2) together mandate that they not be achieved at the expense of required emissions reductions,[8] nor at the risk of undermining the integrity of the allowance system established under title IV.

Consequently, EPA is faced with the task of ensuring the compatible achievement of two distinct policy objectives: first, the Phase I emissions reduction requirements must not be by-passed by load-shifting to unregulated units, and second, utilities must be permitted to continue to operate in an economic and reliable fashion. Accordingly, in addition to the specific planning requirements implementing section 408(c)(1)(B), today's proposal includes an allowance accounting procedure, promulgated pursuant to section 403(d) and set forth in §§ 72.402 and 72.409 of the rules, to address under-utilization and load-shifting that occurs incidental to dispatching or forced outages during Phase I.

To implement section 403(d), the proposed rule would require that an allowance accounting be made at the end of each calendar year for any Phase I affected unit whose under-utilization due to dispatching or forced-outages resulted in emissions increases at non-Phase I affected units. The units that provided compensating generation for this purpose, and not for the purpose of a compliance plan meeting the Phase I emission limitation, would not have to be designated as Phase I affected compensating units. Allowances would, however, be deducted from the Phase I unit's account at the end of the year in an amount equal to the product of (A) the increment (in Btu's) of the unit's under-utilization multiplied by (B) the Btu-weighted average emissions rate for the year of the units providing compensating generation (after

[6] "Baseline" refers to the unit's annual average 1985 through 1987 heat input or utilization measured in mmBtu. With certain specified exceptions, the Acid Rain program allowance allocation scheme established in title IV is based on the unit's baseline utilization. Generally speaking, yearly allowance allocations are calculated by multiplying the baseline for a unit by the presumptive emissions limitation for the Phase. It is important to note that neither the rule nor the statutory provisions are concerned about decreases in utilization at Phase I units that do not cause the unit's total utilization for a Phase I year to be less than its baseline.

[7] New units, having a zero baseline, would not receive any allowance under the formula.

[8] Congress intended that Phase I emissions reductions be achieved not only on a unit-by-unit basis but on an aggregate basis as well. For example, section 404(a)(2) requires the Agency to establish an allowance reserve based on "the total tonnage of reductions in the emissions of SO_2 from all utility units in calendar year 1995 that will occur as a result of compliance with the emissions limitations requirements of this section."

accounting for system-wide downturns, Phase I unit generation, and sulfur-free generation). Under-utilization would, thus, be accorded different regulatory treatment depending upon whether it occurred for the purpose of compliance planning under Phase I.[9]

In sum, EPA is proposing to limit the applicability of section 408(c)(1)(B) to instances where utilities adopt reduced utilization as a method of compliance in order to afford utilities maximum flexibility in relying on economic dispatching and integrated compliance strategies. EPA is proposing under the authority in section 403(d) to require that the designated representative of Phase I units that are under-utilized in any year for reasons other than compliance, and that shift generation to unaffected units, surrender allowances to account for the emissions increases at the unaffected units providing the compensating generation. In this way, allowance banking may not take place without corresponding emissions reductions.

The Agency believes that this approach best implements the express intent of Congress to establish a program that assures that Phase I emissions reductions are achieved, and the "orderly and competitive functioning of the allowance system" is preserved, without interfering with traditional utility dispatching operations.

b. *Concerns addressed by limiting the applicability of section 408(c)(1)(B).* Today's proposal rejects an interpretation of section 408(c)(1)(B) that would apply its provisions to all circumstances involving under-utilization and load-shifting. EPA believes that the appropriateness of the proposed limited applicability of section 408(c)(1)(B) depends on the simultaneous proposed implementation of its mandate under section 403(d). Indeed, in the absence of the latter, EPA believes that it would be compelled to apply section 408(c)(1)(B) to all circumstances involving under-utilization in order to carry out the statutory mandate of ensuring that required emissions reductions are achieved. As is explained further below, such an outcome is neither necessary nor desirable.

(1) Growth at unaffected units. EPA believes that, for purposes of ensuring the integrity of the Phase I emissions reduction program and of the allowance system, only those increased emissions at units not affected during Phase I resulting from shifts in generation from Phase I units are of concern. The balance of the emissions from units not affected during Phase I are not relevant, since those emissions were expected to occur and were accounted for when Congress established the Phase I emissions reduction portion of the Acid Rain program. Were the proposed rule to apply section 408(c)(1)(B) in all instances of under-utilization, such that units providing compensating generation due to economic dispatching became affected units, far greater emissions reductions would occur in Phase I. Specifically, designated compensating units would be allocated allowances, pursuant to the statutory formula, in amounts equal to their mid–1980's utilization and emissions levels. These units would, in turn, be forced to obtain allowances to offset not only emissions occurring due to generation shifted from Phase I units, but also emissions resulting from demand growth between 1985 and 1995. Such a result is contrary to Congressional intent to accommodate growth in demand at Phase II units between 1985 and 2000. (See generally legislative history cited above; Sections 405 (d), (e), (f), and (h) and 406 of the Act; House Rept., No. 952, 101st Cong., 2nd Sess. (1990), p. 343.)

(2) Wholesale power arrangements. The proposed approach fully accommodates the unique problems faced by electric utility systems that routinely purchase power (as well as systems operating with low margins of unused capacity) and that may not be able to provide compensating generation from within their system and may be forced to buy additional power from outside their systems, for example, in the event of a forced outage. Sellers of power might be reluctant to sell power to purchasing systems if it meant that unaffected units providing the power would be subject to Phase I emissions limitation requirements under section 408(c)(1)(B). Under today's approach to under-utilization, including the provisions proposed specifically for dealing with forced outages, a purchasing system could identify and account for emissions increases due to the compensating generation at another utility, by deducting allowances as provided in § 72.409, without having to designate a compensating unit.

(3) Operational flexibility. The Agency believes that the flexibility embodied in today's proposal is essential for large power pools and utility systems, which may vary generation continuously at individual units based on economic dispatching procedures. These arrangements could continue, even if they resulted in incidental under-utilization, without the need for designating compensating units. Similarly, today's approach addresses the compliance problems that would otherwise be faced by utilities that may be unable to designate a compensating unit in the event of under-utilization caused by forced outages.

c. *Distinguishing between section 408(c)(1)(B) and section 403(d) Treatment.* The distinction between section 408(c)(1)(B) and section 403(d) is found in the language of Section 408(c)(1)(B), which states that it applies:

> (i)n the case of a compliance plan for an affected source under sections 404 and 407 for which the owner or operator proposes to meet the requirements of that section by reducing utilization of the unit as compared with its baseline or by shutting down the unit. * * *

Distinguishing between reduced utilization arising in the context of section 408(c)(1)(B) and under-utilization under section 403(d) will inevitably require a retrospective assessment of the reasons for, and circumstances surrounding, any under-utilization.

There are specific factors that would be dispositive of the applicability of section 408(c)(1)(B) and section 403(d). A unit would be treated as subject to section 408(c)(1)(B) if the owners and operators of a Phase I affected unit institute a planned reduction in utilization below the unit's baseline in order to comply with the unit's Phase I emissions limitations.

By contrast, a showing that the net aggregate utilization of all Phase I units in a utility's system was equal to or greater than the aggregate baseline would excuse any under-utilization at a Phase I unit since all the under-utilization would be deemed to be treated as compensated for at those units. In addition, the demonstration of a system-wide downturn would excuse under-utilization to the extent the percentage under-utilization equals or is less than the percentage downturn. With regard to any excess of under-utilization above the level of the downturn, there would be a rebuttable presumption that section 403(d) applies, and section 408(c)(1)(B) would apply only if there is clear and convincing evidence that the planning requirements of section 408(c)(1)(B) was violated. Under-utilization that is the result of a forced-outage would also be treated pursuant

[9] In developing today's proposal, the Agency rejected one interpretation that has been offered of title IV, whereby no "retrospective" allowance accounting requirement would be imposed to account and compensate for under-utilization and corresponding shifts in generation that may occur as a result of forced outages or dispatching. EPA believes that an approach that ignored end-of-year accounting for shifts of generation in any year of Phase I that resulted in emission increases at non-affected units runs counter to the Agency's mandate under section 403(d).

to the provisions of section 403(d). In that regard, a showing that under-utilization was the result of a forced outage would clearly lead only to the applicability of the section 403(d) allowance accounting.

Additionally, to the extent a unit can demonstrate that it had followed one or more of the options specified in its approved compliance plan and that, as of the allowance transfer deadline, the unit held allowances covering emissions that would have occurred in the absence of any reduced utilization, there would be a rebuttable presumption that section 403(d) applies. Under such circumstances, section 408(c)(1)(B) would apply only if there is clear and convincing evidence that the planning requirements were violated.

In the absence of these dispositive cases, EPA would have to consider the full range of circumstances surrounding the specific case of reduced utilization or under-utilization. While no one factor would be dispositive, factors which EPA would consider as possible indications of the applicability of section 408(c)(1)(B) include: A finding that there was a failure to implement additional emissions reduction strategies to comply with the Phase I emissions reduction requirements (in lieu of under-utilization as a compliance means); and a finding that a utility made a fundamental change in the Phase I unit's role within the system, such as shutting down the unit and replacing the generation with generation from a non-affected unit.[10] EPA considers the shutting down of a unit to be virtually dispositive that section 408(c)(1)(B) applies, in the absence of compelling evidence to the contrary.

Factors that EPA would consider as possible indicators of the applicability of section 403(d) include: A demonstration that the under-utilization was due to a change in the dispatch order because of increases in the relative generation costs at the unit to the extent such increases are unrelated to the benefits a utility might derive from the resulting banked allowances. For example, changes in the generation costs might reflect the installation of pollution control equipment at the unit or changes in fuel supply. The rule would also allow EPA to consider other relevant indicators demonstrated by the source. EPA requests public comment on indicators that should be considered to determine the applicability of sections 403(d) and 408(c)(1)(B).

d. *Specifics of Section 408(c)(1)(B) reduced utilization plans and section 403(d) Accounting*—(1) *Net aggregate Phase I utilization threshold test.* Under the proposed rule, accounting for reduced or under-utilization and shifts in generation from a Phase I unit to unaffected units, would not be required under section 408(c)(1)(B) or section 403(d) unless there was a net aggregate reduction below the aggregate baseline at all Phase I units within a source's utility system. For example, if there are two Phase I units within a system, and one decreases its heat input to one million Btu's below its baseline, but the other increases its heat input by two million Btu's above baseline, then the Phase I units in the system will have a net increase in heat input of one million Btu's, and the under-utilization at the first unit will not trigger requirements to account for shifts in generation.

The Agency believes this threshold test is appropriate because it accounts for totally permissible shifts in generation from one Phase I unit to another. Shifts between Phase I units do not warrant further accounting in the way that shifts between Phase I and Phase II units do, simply because all Phase I units are required to hold allowances to offset all of their emissions. Without such a threshold test, a Phase I unit might trigger accounting requirements if its heat input drops below baseline even if generation was shifted to another Phase I unit and the emissions increases were accounted for.

(2) System-wide sales downturn threshold test. The proposed rule would allow under-utilization at a Phase I unit without requiring designation of a compensating unit to the extent that the reduction below baseline resulted from a system-wide decline in kilowatt hour sales for the year (as compared with the previous year) due, for example, to an economic downturn or unusual weather. (The "system", for the purpose of making such a showing, would be defined as the generating units controlled by the same utility operating company.) No allowance accounting or additional planning requirements would apply under sections 408 or 403(d), in the event the percentage reduction below baseline was demonstrated to be less than or equal to the percentage system-wide sales decline. The Agency believes that this is a reasonable approach because in cases of system-wide declines in generation and purchases there would be no corresponding shifts of generation to unaffected units. Only in cases where a Phase I unit experienced reduced utilization of a percentage that exceeded the percentage of system-wide downturn in sales would a shift of generation to one or more unaffected units be indicated. For example, if a system's total sales dropped by 15 percent from the previous year, the Phase I unit's drop in utilization from the baseline would be excused up to 15 percent. EPA requests public comment on this approach.

(3) Section 408(c)(1)(B) reduced utilization plans—(a) General requirements. Under today's proposal, when reduced utilization is used as a planned compliance strategy the designated representative must file a reduced utilization plan with EPA, in accordance with § 72.43. If the load is being shifted to an otherwise unaffected unit, the plan must designate the compensating unit. The designated compensating unit would become an affected unit for Phase I for all purposes. If the compensating unit designated in the plan is located at another source, the source would become an affected source and the designated representative for the source would be required to submit a Phase I permit application. EPA would allocate allowances to the designated compensating unit in an amount approximately equal to its 1985 emissions, pursuant to the statutory formula specified in section 408(c)(1)(B).

(b) *Sulfur-free generation plans.* If the reduced utilization plan proposes to shift load to a generator that does not emit SO_2 (e.g., a renewable energy generator), the proposed rule would require the designated representative to submit a Sulfur-free Generation Plan and make certain demonstrations and certifications to ensure that no SO_2 would be emitted.

(c) *Energy conservation and improved unit efficiency plans.* Section 408(c)(1)(B) of the Act does not require the designation of a compensating unit when reduced utilization occurs at a Phase I unit as a result of a program of energy conservation or improved unit efficiency measures, since these cause decreases in utilization without any shifts of generation to unaffected units. To get credit for such measures, the proposed rule requires that energy conservation and improved unit efficiency programs be described in the unit's proposed compliance plan, and that kilowatt hour savings resulting from such measures be verified by an independent auditor, by the utility's State rate regulator or, for electric utilities not subject to the jurisdiction of a State utility rate regulatory authority, by the entity with utility rate regulatory

[10] Subject to a decision in the final rule on whether NO_x limits apply to designated compensating units. Another factor would be a finding that the utility had unaffected units that would have to meet a Phase I NO_x emissions limitation if they had been designated as compensating units. (See further discussions below).

authority for such utility. Both demand- and supply-side measures would be energy conservation measures for a demonstration of reduced utilization due to energy conservation. (Cf. The Conservation and Renewable Energy Reserve program in 40 CFR part 73 of today's proposal.)

The proposed rule provides that any utility reducing utilization at a Phase I unit as a result of an approved energy conservation program would be required to verify its utility system's energy savings annually. In order to encourage the use of aggressive energy conservation programs the rule provides that all verified energy savings in a system resulting from such a program could be attributed to the affected unit. In addition, the rule provides that units may be credited with energy savings achieved by measures initiated between the baseline period and 1995. EPA proposes two methods for verification of reduced utilization due to energy conservation or improved unit efficiency: (1) Using the EPA Conservation Verification Protocol of 40 CFR part 73, subpart F (scheduled to be published at a later date); or (2) by the State utility rate regulator, provided that only States that have adopted least-cost planning practices and net income neutrality rules for investments in energy conservation would be qualified to verify demand-side measures. (See further discussion of part 73, subpart F). EPA is not proposing to require the use of the EPA Conservation Verification Protocol in States with least-cost planning practices and net income neutrality rules since regulatory scrutiny in such States is likely to be rigorous.

EPA recognizes that it may be difficult for a utility to verify energy savings for the entire year within the 30-day deadline for submitting annual reports provided for in subpart K. Thus, the rule proposes that the annual report would only be required to verify energy savings through the third quarter (September 30) of the calendar year. Based on this verification, the annual report would include an estimate of energy savings for the fourth quarter. Verification of energy savings occurring during the fourth quarter would be due with the next quarterly report for the source, i.e., by April 1 of the following calendar year. If the verified energy savings for the fourth quarter were less than the preliminary estimate, the utility would be required to account for the compensating generation and emissions that represented the shortfall in expected energy savings. EPA requests comment in particular on any issues of timing raised by this approach to the verification of energy conservation and improved unit efficiency.

(d) *Failure to submit a section 408 plan.* EPA is proposing that in cases where a Phase I unit's utilization fell in any calendar year below its baseline, and where such decreased utilization was not governed by an approved reduced utilization plan, and was the result of a compliance strategy that relied on such reduced utilization, the designated representative, owners, and operators of the unit would be held liable for violating the planning requirements of section 408(c)(1)(B) if no reduced utilization plan were submitted. EPA proposes a three tiered approach to determine whether the reduced utilization planning requirement was violated in any one year.

Under the first tier, a Phase I unit with under-utilization would be deemed not to have violated the reduced utilization planning requirements of section 408(c)(1)(B) to the extent its under-utilization during the year was: (a) Accounted for by a reduced utilization plan (including an energy conservation, a boiler or generation efficiency improvement plan, or a sulfur-free generation plan); (b) offset by over-utilization at other Phase I units within the unit's system such that aggregate utilization for all the Phase I units within the system was at least equal to the aggregate baseline for these units; (c) equal to or less than the percentage of a system-wide downturn in sales (in Kwh); or (d) a result of a forced outage at the unit.

Under the second tier, it would be presumed that there is no violation of the section 408(c)(1)(B) planning requirements to the extent the designated representative of the unit demonstrates that the unit was operated in accordance with an approved compliance plan with the result that the unit held sufficient allowances to cover sulfur dioxide emissions that would have occurred but for the under-utilization. In addition, where there was a system-wide downturn but the percentage of under-utilization exceeded the percentage of system-wide downturn, it would, nevertheless, be presumed that section 408(c)(1)(B) is not violated. The rebuttable presumptions of this second tier would, however, be overcome by a finding, based on clear and convincing evidence, that the reduced utilization planning requirements were violated.

To the extent the above two tiers do not account for the total amount of under-utilization, EPA proposes to apply a third tier of indicators on a case-by-case basis to determine the applicability of section 408(c)(1)(B). The indicators include, but are not limited to, (a) two indicators that the under-utilization was not planned: (1) That the under-utilization resulted from changes in the unit's utility system dispatch order resulting from increases in the relative cost of generation at the unit (except to the extent that the change in dispatch order was a result of the savings resulting from banked allowances), and (2) that measures were taken at the unit to cut its emissions rate to 2.5 lbs/mmBtu or less (e.g., evidence of low-sulfur coal reserves on hand); and (b) two indicators that the planning requirement was violated: (1) Whether the under-utilization was due to a fundamental change in the unit's role within the utility system (e.g., a total shutdown of the unit), and (2) whether the utility failed to implement any other compliance strategies.[11] In addition, the rule authorizes the Administrator to consider any other relevant information provided by the source, including the degree to which reduced utilization was used to meet the unit's emissions limitation requirements. EPA believes that this three-tiered approach will assist utilities in determining whether they are required to submit a plan pursuant to § 72.43.

If EPA determines that the unit should have filed a reduced utilization plan, full compensation for the increased emissions at the compensating units would be required, and excess emissions penalties would be assessed pursuant to section 411 and part 77 of today's proposal. Finally, the designated representatives for the under-utilized and compensating units would be required to submit not later than the deadline for the annual compliance certification report (due January 30th of each year), a reduced utilization plan designating a compensating unit.

(e) *Applicability of NO_x requirements* to compensating units under section 408(c)(1)(B) reduced utilization plans. The Agency considered two opposing views regarding whether the Phase I NO_x emissions limitations must be met by otherwise unaffected units (e.g., appendix B units) that are designated as compensating units in an approved reduced utilization plan. The proposed rule does not apply Phase I NO_x emissions limitations to compensating units. There are, however, textual arguments that can be made from the

[11] Subject to a determination in the final rule as to whether designated compensating units will be subject to NO_x limits. Another indicator is whether the utility had a reason to try to avoid the NO_x obligations that would have to be met by a compensating unit. (See further discussion below.)

statutory language to support both views. EPA, therefore, requests public comment on this issue.

The relevant statutory language concerning this issue is in sections 407(a) and 408(c)(1)(B) of the Act. Section 408(c)(1)(B) provides:

The unit to be used for such compensating generation, which is not otherwise an affected unit under sections 404 and 407, shall be deemed an affected unit under section 404, subject to all of the requirements for such units under this title, * * *.

In addition, section 407(a) states:

On the date that a coal-fired utility unit becomes an affected unit pursuant to sections 404, 405, 409, or on the date a unit subject to the provisions of section 404(d) (Phase I extensions) or 409(b) (repowering extensions) must meet the SO_2 reduction requirements, each such unit shall become an affected unit for purposes of this section and shall be subject to the emission limitations for nitrogen oxides set forth herein.

Under the first view, designated compensating units that were not otherwise subject to Phase I of the Acid Rain program would not be subject to the section 407 NO_x emissions limitations. This view would be based on the belief that Congress was concerned primarily with SO_2 emissions reductions in Phase I, and was either not concerned with shifts in NO_x emissions to unregulated compensating units or thought that the effects of such shifts would be minimal. This view is supported by the phrase in section 408(c)(1)(B) providing expressly that otherwise unaffected compensating units become affected "under section 404", but does not state that the units also become subject to section 407. In addition, although section 407(a) provides that a coal-fired utility unit becomes subject to the NO_x requirements on the date that it "becomes an affected unit pursuant to sections 404, * * *", Congress did not include section 408(c)(1)(B) in the list of sections giving rise to NO_x applicability.

The same two statutory provisions can, however, also be read together as requiring otherwise unaffected compensating units to comply with the applicable limits. Since section 408(c)(1)(B) states that compensating units become affected units "under section 404, subject to all of the requirements for such units under (title IV)", the applicability of the NO_x limits to units when they become affected "pursuant to section 404" would include units designated as compensating units. This view would be based on the belief that Congress intended section 408(c)(1)(B) to prevent the shift of not only SO_2 but also NO_x emissions to units not otherwise affected during Phase I. This view is further supported by the express references to section 407 in section 408(c)(1)(B).

Because of the difficulties in reconciling the conflicting inferences which can be drawn from the textual material, and particularly given the complexity of the regulatory scheme, the Agency must adopt a construction of the statute that "represents a reasonable accommodation of * * * competing interests," following "detailed and reasoned" consideration of the issues. *Chevron, U.S.A.* v. *NRDC*, 467 U.S. 837, 865 (1984). The Agency, therefore, asks for comment in order to judge the relative weight (and wisdom) of the two views based on consideration of the full rulemaking record.

(f) *Termination of compensating unit plans*. The proposed rule allows units subject to compensating unit plans to terminate such plans and to de-designate compensating units in a plan. As a pre-condition of such termination or de-designation, the affected compensating units must surrender allowances equal to those allocated pursuant to the compensating unit plans. This is to ensure that future-year allowances, equal to those allocated to the compensating unit under the presumption that the unit would continue to be affected for the remainder of the Phase, cannot be used in future years when the de-designated compensating unit is no longer affected and no longer making verified emissions reductions. To effectuate the surrender of such allowances, the rule requires that before the reduced utilization plan can be terminated, or a compensating unit is de-designated, the compensating unit's Allowance Tracking System subaccounts must include allowances, equivalent in number and compliance use date, to those allocated pursuant to the compensating unit plan for the remaining years of Phase I. When the plan is terminated, the Agency will deduct the allowances from the compensating unit's account.

(4) Section 403 accounting. Generally, today's proposal specifies that, pursuant to Section 403 of the Act, any Phase I unit that experiences utilization below its baseline as calculated at the end of the year would, subject to the threshold tests discussed above, have allowances deducted from its Allowance Tracking System account to account for the shifts in generation and consequent emissions increases at unaffected units. Of course, the very nature of the electric utility industry operating through international grids of intra- and inter-connections, as well as complex variations of business relationships, eludes precise definition of where compensating generation is in fact being provided. The formula proposed in today's rule would serve as a proxy for calculating the actual emissions resulting from load-shifting that would otherwise be unaccounted for.

The accounting procedure proposed in today's rule would be accomplished as follows. Pursuant to subpart C of today's proposal the designated representative for each Phase I unit would include in the permit application information identifying the NERC region or subregion where the Phase I unit operates. This broadly identifies the universe of units which may provide compensating generation for a Phase I unit as a result of dispatching. EPA is requesting comment on the feasibility of assembling and processing the data required to calculate NERC region average emissions rates as of the end of the allowance transfer deadline. The Agency acknowledges that NERC regions and subregions contain a large number of units and a number of different utility operating companies. It may be difficult for individual utilities to coordinate and assemble the necessary data on emissions rates and utilization levels in a relatively short period of time. One approach under consideration is to allow utilities to use utilization and emissions data from the four consecutive quarters running from September 1 of the previous year to September 1 of the year for which the compliance certification is being made. The Agency requests comment on this approach and on other approaches for facilitating the calculations of NERC region average emissions rates.

At the end of the year, pursuant to the annual reporting and compliance certification procedures in § 72.409 of subpart K, a utility would take the following steps to account for incidental under-utilization: [12]

First, the utility would determine whether any of its Phase I units had utilization below baseline. If not, no further accounting would be necessary.

Second, the utility would calculate whether it meets the threshold test for aggregate Phase I under-utilization, i.e., whether, when viewed collectively, the aggregate utilization for all of the utility's Phase I units was below an aggregate baseline for these units. If the aggregate utilization for the utility's Phase I units was equal to or greater than the aggregate baseline, no further

[12] The term "incidental under-utilization" implies that the under-utilization was not due to a failure to plan. It also implies that the decrease is not accounted for using the net-aggregate Phase I utilization and system-wide downturn threshold tests.

accounting for under-utilization would be necessary.

Third, the utility would determine whether it meets the threshold test concerning system-wide sales downturn, i.e., the extent to which the percentage of under-utilization is matched by the percentage of system-wide downturn. For example, if a utility system has experienced a decline in kilowatt hour sales of 1% during the year, and each of the utility's under-utilized units has been under-utilized by less than or equal to 1% of its baseline, then no further accounting would be necessary for under-utilization.

Fourth, using the formulas specified in the rule the utility would determine how much under-utilization is unaccounted for at each unit after subtracting the effects of: (a) Shifts of utilization to other Phase I units within the utility's system; (b) system-wide downturn in sales; (c) shifts of utilization to other Phase I units within the NERC region of which the utility is a part; and (d) under-utilization accounted for by an approved reduced utilization plan.

Fifth, if after the above four steps the utility determines that not all the under-utilization at the unit can be explained and accounted for, it would then determine the emissions rates at which it will calculate allowances to be deducted as provided in the rule. As proposed today, the utility would have a choice between two different approaches. The first approach is the NERC region or subregion average emissions rate. Under this option, the utility would calculate an average emissions rate based on all the units within its NERC region or subregion. The calculation provided for in today's proposal would weight each unit's emissions rate by the number of Btu's it utilized over baseline.[13]

The second approach is the system average emissions rate. Under this option, the utility would base its average emissions rate on units within its own system *plus* any other units outside of its system for which it can document specific amounts of generation. The utility would also have the option to use the NERC system average emissions rate for any portion of generation outside of its system that could not be tied to any specific unit.

In addition, the Agency considered other formulas for calculating average emissions rate of compensating generation. Under another less complex formula the Agency is considering, allowances would be deducted from the Phase I unit's Allowance Tracking System account equal to the Btu's the unit reduced below its baseline times the under-utilized Phase I unit's actual annual average emissions rate. This simplified formula would apply subject to a demonstration by the source that the compensating generation was actually provided at a different emissions rate. A variation of this formula would be to multiply the Btu's of under-utilization by 2.5 lbs/mmBtu, the presumptive Phase I emissions limitation.

Finally, the Agency considered but rejected an approach that would require each Phase I unit to include a list in its permit application of every other unit in its utility dispatch order, including any units used by other utilities that are relied on by the Phase I unit's utility to meet electricity generating obligations. The end of year accounting in the event of under-utilization would be based on the annual average emissions rate of those units. The Agency decided against such an approach since it would unnecessarily complicate and burden the initial permitting process.

(a) Treatment of NO_x. EPA is proposing that NO_x requirements would not have to be met by unaffected units providing compensating generation as a result of incidental shifts in generation not subject to Section 408(c)(1)(B), since Section 403(d) of the Act is only concerned with SO_2.

(b) Treatment of forced outages. As mentioned above, reduced utilization and shifts in generation resulting from forced outages would also be subject to Section 72.409 compliance certification and allowance accounting procedures proposed today pursuant to Section 403(d). In the case of a forced outage, a designated representative would document that an outage was due to unavoidable circumstances. The rule would also require a demonstration that the utility took steps and/or continues to take steps to restore the unit to service as expeditiously as practicable.

e. *Timing of accounting period.* EPA considered two approaches for accounting for reduced utilization: a one-year accounting period and a five-year accounting period. Under the one-year approach, proposed in the rule, accounting would be required at the end of each year of Phase I. Allowances would be surrendered to account for the actual emissions from increased utilization at unaffected units due to load-shifting from Phase I units during the year.

Under a five-year approach, utilities would average utilization at Phase I units over the five-year Phase I period. At the end of each year utilities would place allowances equivalent to any under-utilization in a special allowance escrow account. If utilization increased above baseline at any Phase I units in a system in a subsequent year, the escrowed allowances could be used to offset the increased emissions. At the end of the five-year period, the utility would be required to surrender banked allowances only for any net under-utilization at Phase I units. The five-year approach, however, focuses exclusively on Phase I unit utilization and would not account for increases in emissions at the unaffected units providing compensating generation in any given year. EPA believes that the objective of both section 403(d) and section 408(c)(1)(B) is to account for annual emissions, not just utilization. Under a five-year approach, allowances that would have to be deducted from a unit's account under the approach proposed today would be available to offset emissions. The environmental effects would plainly be adverse.

In addition, a five-year accounting period would be inconsistent with the annual allowance allocation and compliance demonstration requirements mandated by the Act. The five-year approach does not account for annual increases in SO_2 emissions due to reduced utilization and load-shifting.

Finally, as is noted above, utility systems would have the flexibility under the one-year approach proposed today to dispatch generation cost-effectively and to deal with forced outages. Thus, the Agency believes that today's proposal allows for changes in load and operating conditions at electric utility systems without diminishing the emissions reductions contemplated by the Act.

5. Phase II Repowering Extensions

Section 409 of the Act authorizes the Administrator to grant a four-year extension of the Phase II emissions reduction deadline where a unit repowers with a qualified technology. In addition, under certain circumstances, an existing utility unit may qualify for the extension if it is to be shut down and replaced with a new unit located at a different site but using a qualified repowering technology.

[13] EPA requests comment on how to establish baselines for sulfur-free generators for purposes of this calculation. In addition, EPA requests comment on how to treat shifts in generation to facilities outside the United States. Today's rule would not require United States utilities to designate foreign compensating units or to account for under-utilization due to shifts in generation to sources outside the United States, including surrendering allowances for emissions increases resulting from such shifts

a. *Effect of repowering extension.* During the "repowering extension period", a unit satisfying the criteria for eligibility and meeting the procedural requirements for repowering will not be subject to the otherwise applicable emissions limitation requirements for SO_2 and NO_x but instead will be allocated allowances under section 409(c)(1) of the Act, implemented at § 72.44(f)(3). EPA today proposes that the repowering extension period begin on January 1, 2000 and end on the date on which the affected unit for which the extension has been granted will be removed from operation to install the repowering technology or will be permanently removed from service for replacement in accordance with § 72.44(b)(2), but no later than December 31, 2003. Thus, the repowering extension period will be unit specific. EPA believes this interpretation is consistent with the allowance allocation scheme developed in section 409(c). In particular, section 409(c)(2) states that upon the date the unit is removed from operation, the unit will be subject to the emission limitations of section 405 of the Act.

b. *Prohibitions on termination of approved repowering extension plans.* Generally, today's proposal authorizes sources to terminate compliance options using the subpart J permit revision procedures. This general flexibility would not, however, apply in the case of approved repowering extension plans after Phase II begins. Specifically, units granted a repowering extension will have benefitted from the receipt of additional extension allowances, some of which were allocated to the units pursuant to a pro rata ratchet on the allocation for all other Phase II units. EPA believes that it would, therefore, be unfair to allow sources to terminate repowering extension plans after they have benefitted from the allocation of extension allowances. Approved repowering extension plans could, thus, be terminated only until December 31, 1999.

c. *Treatment of failed and abandoned repowering project.* The proposal states that, if after construction and testing of a repowering technology a source determines that the repowering technology is infeasible, the source would not be in violation of the Act, provided it demonstrates that it had proceeded with the repowering project in good faith. However, the source would not be eligible for allocations of additional extension allowances beyond the four year extension period in such cases. This is pursuant to section 409(b)(2) of the Act, which addresses situations in which a repowering technology fails to achieve desired emissions reductions and is economically or technically infeasible. EPA is proposing that in such cases, where (as provided in the Act) the designated representative demonstrates that the technology has been properly constructed and tested, the source's failure would not be a violation of the Act and extension allowances would continue to be allocated for the remainder of the repowering extension period. Upon expiration of the repowering extension period, however, the Administrator would allocate allowances to the unit according to the unit's standard Phase II allocations pursuant to section 405. EPA believes that this is an appropriate interpretation of Congressional intent for this provision because it avoids penalizing utilities that attempted to comply with Acid Rain requirements through the use of innovative or experimental technologies.

EPA considered several other interpretations of section 409(b)(2). Under one approach the source would have to surrender the extension allowances or pay other penalties in cases of failed repowering projects. Such an approach would, however, be clearly contrary to the intent of Congress, which included section 409(b)(2) in the Act to ensure that the use of nonconventional technologies would not increase utilities' exposure to noncompliance penalties.

EPA also considered whether it should continue to provide extension allowances beyond the four year extension period in the event of a failed repowering project. EPA rejected this interpretation because the allocation of extension allowances beyond December 31, 2003 is not expressly provided for in the Act. Moreover, providing extension allowances beyond the extension period provided for in the Act would increase SO_2 emissions above the levels that would otherwise be allowed annually during Phase II, thereby causing an additional, negative environmental impact. The Agency believes that the ability to buy allowances on the market gives utilities the flexibility and time to consider other technological options for meeting Phase II emissions limits, without the necessity for further extensions.

Finally, EPA considered whether extension allowances should be granted in cases where a utility decides before it has completed construction that a repowering technology is infeasible, and the Agency makes a determination that the utility has proceeded in good faith. Two scenarios relevant to this issue are possible: (1) A utility applies for and receives a repowering extension by December 31, 1997, but determines prior to beginning construction that the repowering technology is economically or technologically infeasible and abandons the project; (2) A utility successfully demonstrates preliminary engineering and existence of the required contracts prior to the January 1, 2000, deadline, and begins construction. However, the technology proves infeasible prior to the completion of construction.

In both cases it could be argued that a utility would be faced with little time to meet the Phase II emissions limitations. Thus, without the assurance of an extension few utilities would attempt repowering as a method of compliance.

Today's proposal, however, allows the extension where a repowering project is abandoned before construction is commenced. EPA is concerned that providing extensions in cases such as the first might lead to attempts to circumvent the Phase II emissions deadline by submitting repowering extension applications without a serious intent to repower. The second scenario is more difficult. EPA believes, however, that both scenarios are contrary to the intent of Congress. The Agency notes that although the original Senate bill (S. 1630) had no requirement that construction and testing of the repowering technology be completed, the repowering provision enacted by Congress included this language. Thus, EPA believes that Congress intended to preclude extensions where construction and testing were not completed. Nevertheless, the Agency requests comment on the issues raised by Scenario 2. Specifically, EPA is interested in the types of demonstrations or other requirements that might be implemented if extensions until December 31, 2003 were granted in such cases. EPA is particularly interested in requirements that would safeguard against frivolous applications and efforts to circumvent the Phase II emissions deadline.

d. *Repowering application process.* The proposed rule provides for a two-tiered process by which a designated representative would apply for a repowering extension. The first tier of the repowering extension application process would involve submission of a repowering extension compliance plan to the permitting authority by January 1, 1996, the deadline for Phase II permit applications. The plan may be submitted for conditional approval. However, the designated representative would be

required to notify the permitting authority by December 31, 1997 of his or her decision to activate or withdraw the proposed compliance plan. EPA believes that the ability to activate or withdraw the repowering proposal gives utilities the flexibility to reconsider repowering plans up until the December 31, 1997 deadline provided for in section 409(a) of the Act.

The second tier would be conditional approval of the repowering technology, a petition for which would have to be submitted to EPA before June 1, 1997. This deadline allows EPA and DOE six-months to review the technology and make a determination regarding whether the technology conditionally qualifies for an extension. Without such a deadline, it would be difficult for EPA and DOE to review all proposals before the December 31, 1997, deadline for the permitting authority to approve or disapprove the Phase II permit applications. It is important that this deadline be met so EPA will have adequate time to revise and publish the Phase II allowance ratchet before the June 1, 1998 deadline specified in section 403(a) of the Act. EPA believes it is in the interest of any source wishing to repower to submit repowering technology petitions as soon as possible to avoid possible delays in the review of petitions. The Agency requests comment on the June 1, 1997 deadline for submitting this petition.

e. *Qualifying repowering technology.* Section 402(12), in relevant part, defines "repowering" as follows:

> Replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or as determined by the Administrator, in consultation with the Secretary of Energy, a derivative of one or more of these technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of the date of enactment of the Clean Air Act Amendments of 1990 * * *.[14]

The definition thus provides for three major categories of repowering technologies: (1) Technologies specifically listed in the statute; (2) derivatives of one or more of these listed technologies; and (3) technologies which: (a) Are capable of controlling multiple combustion emissions simultaneously; (b) with improved boiler or generation efficiency; and (c) with significantly greater waste reduction than technologies in widespread commercial use as of the date of enactment of the Act (November 15, 1990).

(1) Proposed approach. In accordance with the language of the statutory definition of repowering, the proposed rule provides that a qualifying repowering technology must involve "replacement" of an existing boiler. The language of section 402(12), though ambiguous in many significant respects, will not support an interpretation which fails to recognize that repowering requires use of an appropriate new technology instead of the existing boiler.

EPA considered whether the reference to boiler replacement in section 402(12) could be read as referring to only the first category of technologies. However, such an approach would require reading the provision as if the recital of the three alternative technologies began immediately after the phrase "repowering means", rather than after the phrase "repowering means replacement of an existing coal-fired boiler with one of the following clean coal technologies:".

Such a reading is inconsistent with the structure of the provision, in which the colon, which is "used chiefly to direct attention to matter that follows (as a list, explanation, or quotation)", See Webster's Ninth New Collegiate Dictionary 266 (1985), follows rather than precedes the reference to boiler replacement. Moreover, all three categories of technologies would be properly described as "the following clean coal technologies:".

While it is true that the list following the colon, like the phrase "the following clean coal technologies," could be read to refer exclusively to the seven named technologies (or to those technologies and their approved derivatives), such an interpretation would still fail to provide a satisfactory explanation of the grammatical structure of the provision. Either of these two readings would fail to explain how the technologies that, according to those readings, do not consider boiler replacement, relate to the term "repowering". In other words, if the concept of boiler replacement were removed from either the third category of technologies or from both the second and third categories, the provision would read, with respect to those categories:

> The term "repowering" means * * * a derivative of one or more of (the seven) technologies, and any other technology capable of (meeting the three performance criteria).

The difficulty with this reading is that "repowering," whatever the precise scope of its definition, clearly means doing something with a derivative technology or a multipollutant control technology, rather than simply those technologies themselves. Requiring boiler replacement for all three categories avoids this particular infirmity.

EPA also considered another textual argument that could be advanced to support an interpretation of section 402(12) that boiler replacement is not required for the third category of technology, but it also is unpersuasive. It simply does not follow from the fact that the category of multipollutant control technologies alone has expressly enumerated performance criteria and that those criteria are meant to be the exclusive test for qualifying technologies of these types. Because the third category of technology was intended to encompass types of technologies which were unknown on the date of enactment (and thus, unlike the prior categories, not susceptible to being enumerated in the statute) that category would necessarily have to include explicit defining criteria, whether or not the boiler replacement criterion applied to it. By the same token, the fact that the latter two categories are subject to EPA approval in consultation with DOE does not imply that this is the only criterion applicable to them. Each is subject to additional criteria (i.e., the requirement of derivation in the case of the second category, and the three performance criteria in the case of the third category).

The pivotal phrase "replacement of an existing coal-fired boiler" is undefined in the statute, and its scope is not clearly delineated by its context. Some of the seven listed technologies may not require total boiler replacement, although all require such extensive changes to the boiler that they are tantamount to boiler replacement. Under the principle of ejusdem generis, therefore, the Agency clearly has, at a minimum, ample discretion to treat as functional boiler replacement any changes broadly similar in scope to those involved in installing the seven named technologies. Such a definition would clearly represent the lower, not the upper, limit on the Agency's discretion to give meaning to the term "replacement". Accordingly, the statute confers on EPA the additional discretion to define boiler replacement in a

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[14] The last sentence in the definition of "repowering" in section 402(12) of the Act refers to a specific clean coal technology project in Tallahassee, Florida (Arvah B. Hopkins Station Unit 2 Circulating Fluidized-Bed Repowering Project) awarded November 30, 1990.

functional manner that takes into account achievement of the specified performance criteria as well as the degree of changes to the boiler. By way of example, it should be noted that in the recently proposed WEPCO rule the Agency proposed to consider a unit to be "replaced" if it would "constitute a reconstructed unit within the meaning of 40 CFR 60.15." 56 Federal Register 27636 (June 14, 1991). 40 CFR 60.15 defines "reconstruction" as:

The replacement of components of an existing facility to such an extent that (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (2) it is technologically and economically feasible to meet the applicable standards set forth in this part.

In short, because "Congress has not directly spoken to the precise question at issue," *Chevron, U.S.A.* v. *NRDC*, 467 U.S. 837, 842–43 (1984), EPA enjoys a significant measure of discretion to determine to what extent replacement of less than 100% of the parts of an existing boiler could be deemed replacement for purposes of section 402(12).

In accordance with the above language EPA proposes to use the 40 CFR 60.15 test for "reconstruction" as general guidance in determining whether each individual application under section 409 involves sufficient replacement to qualify for a repowering extension. The Agency seeks comment on this approach and also seeks comment on whether there are other alternative interpretations of "replacement" that are appropriate. In addition, the Agency solicits comment concerning whether, instead of issuing general guidance pertaining to the definition of replacement, the Agency should promulgate specific regulatory requirements concerning the definition of "replacement" applicable to all repowering extension applications.

Finally, EPA notes that utilities are free to use any technology to comply with Acid Rain program requirements within the regular time-frame for compliance with Phase II emissions limits, or to bank allowances and control emissions earlier or later than January 1, 2000. Failure to qualify for a repowering extension does not preclude a source from employing a clean coal technology. In fact, the underlying philosophy of title IV is to encourage technological innovation by giving utilities the flexibility to choose the most cost-effective technology and schedule for meeting emissions limitations.

6. New Unit Plans

New units are defined in Section 402(10) of the Act as units which commenced commercial operation on or after November 15, 1990. Such units are generally subject to the Acid Rain program during Phase II. The proposed rule would require new units to begin complying with the Phase II Acid Rain emissions reduction requirements upon "commencement of operation," i.e., when the unit begins emitting SO_2 and NO_x.

Although most new units which commence operation between enactment and 1995 will receive some allowances pursuant to section 405(g) of the Act, new units which commence commercial operation after 1995 will receive no allocations. Rather they are required under title IV to obtain allowances to cover their SO_2 emissions from the market. A detailed discussion of which new units would be allocated allowances can be found in the preamble discussion of 40 CFR Part 73.

Although new units are generally not subject to Acid Rain program emissions reduction requirements until Phase II, a new unit may become an affected unit during Phase I if it shares a common stack with a Phase I affected unit and does not monitor emissions independently (or has not been approved for alternative monitoring pursuant to 40 CFR part 75), or if it is designated as a compensating unit in a reduced utilization plan. Today's proposal specifies that each such new unit would not be allocated allowances during Phase I and would be deemed to have a baseline of zero. Although under section 405(g) the Administrator is authorized to allocate allowances to some new units, beginning on January 1, 2000, the statute does not provide for these units to receive allowances in Phase I. The Agency requests comment on this treatment of new units that become affected units in Phase I.

a. *Proposal*. Section 72.45(a) specifies the units to which this provision would apply. These include two categories of units: (1) those which commenced commercial operation on or after November 15, 1990, and (2) those which served a generator with a nameplate capacity of 25MWe or less before November 15, 1990 but which on or after November 15, 1990, serve a generator with a nameplate capacity of greater than 25MWe.

Although the statutory definition of existing units does not include simple combustion turbines and units which serve a generator with a nameplate capacity of 25MWe or less, title IV defines "new units" to include these types of units.

Today's proposal specifies, in accordance with the Act, that any new unit, including a simple combustion turbine or a unit that serves a generator of 25MWe or less is subject to the requirements of the Acid Rain program. The Agency requests comment on the effect of this requirement on very small units, and whether a de minimis exclusion should be included in the final rule. For example, such an exclusion might be appropriate for emergency generators used by hospitals that do not otherwise provide peak load generation for a system.

b. *Special deadlines*. The designated representative of a new unit would be required to submit a permit application to the permitting authority not later than 24 months before the later of January 1, 2000, or the date on which the unit "commences operation." Two proposed exceptions to this deadline are if a new unit serves as a compensating unit in a reduced utilization plan during Phase I or the new unit becomes affected during Phase I because of the provisions dealing with units using a common stack. Such a unit would be required to submit its permit application at the time the reduced utilization plan or common stack plan is due, i.e., the later of February, 1993 or 24 months before commencing operation.

c. *Compliance upon commencement of operation*. The Agency proposes that in the permit application for a new unit, the designated representative include a "commence operation" schedule. This information is necessary to confirm the date on which the unit becomes an affected unit. It is especially important for units which commence operation after Phase II begins because the permitting authority, the Agency, and the source need to know the exact date upon which compliance begins.

The Agency proposes, in accordance with section 408(e) of the Act, that the designated representative of a new unit hold allowances to cover the annual SO_2 emissions at that unit beginning in the year that the unit commences operation.

d. *New unit emissions monitoring requirements*. The emissions monitoring at 40 CFR part 75 proposes that new units must account for their emissions upon commencement of operation. 40 CFR part 75 also specifies a default methodology for calculating emissions for any period before the monitors are fully operational.

e. *Other options considered*. The Agency considered allowing new units to begin compliance with the Act upon "commencement of commercial

operation", but rejected this approach because emissions during the period between "commencement of operation" and "commencement of commercial operation" could be significant. Under NSPS requirements this period could last for as long as 180 days. Congress intended that any emissions above the 8.95 million ton cap for sulfur dioxide for Phase II should be avoided. The Agency, thus, believes start-up emissions emitted by new units should be accounted for.

7. Nitrogen Oxides Options—Generally

Section 407 of the Act requires that the Administrator promulgate nitrogen oxides emissions limitations for boilers [15] that are affected units under the sulfur dioxide requirements of title IV of the Act.

As is indicated in part I of this preamble, the Acid Rain program emissions limitations for NO_x will be promulgated at 40 CFR part 76 at a later date. The Acid Rain compliance options for NO_x discussed in subpart D of today's proposal are, therefore, only a partial proposal of the NO_x requirements under the program. Because NO_x requirements will be included in Acid Rain permit applications and permits, today's proposal includes a framework for the NO_x compliance options which will be addressed more substantively in the 40 CFR part 76 rulemaking. If appropriate, following consideration of public comment on this proposal, EPA may determine to publish all the NO_x compliance options rules in the 40 CFR part 76 regulations.

The three NO_x compliance options proposed in this section have significantly different environmental effects. Nitrogen oxides emissions averaging plans are the most environmentally neutral of the three options because they must ensure the emissions reductions that would be achieved by strict compliance with the applicable NO_x limitation for each unit. Nitrogen oxides compliance deadline extension plans allow for emissions in excess of the emissions that would be achieved by strict compliance for a limited period. Nitrogen oxides alternative emissions limitation plans allow for a permanent limitation in excess of that which would otherwise be required pursuant to 40 CFR part 76. The latter plan is, therefore, the option most likely to impact the environment. The Agency has proposed the requirements for these three options with the intent of providing maximum flexibility, while being cognizant of their potential environmental effect. Because the NO_x emissions averaging and NO_x alternative emissions limitations options are available in Phase I and Phase II, the Agency seeks to provide for consistent implementation of these requirements nationwide. The NO_x alternative emissions limitations provisions are especially prone to inconsistent application because of the individual nature of each request and the judgments that will have to be made by the reviewer of the application rather than on standardized formulas and criteria. The approach proposed today seeks to minimize the potential for inconsistent treatment of sources State-to-State and to help ensure expeditious permitting by setting forth a framework for the specific requirements for approval of the three NO_x compliance options.

[15] Section 402 of the Act defines the term "unit" to mean any "fossil fuel-fired combustion device." This can be a boiler, a turbine, or any other fossil fuel-fired device. The nitrogen oxides requirements of section 407, however, apply only to units that are boilers.

8. Phase I or Phase II Nitrogen Oxides Emissions Averaging Plans

Pursuant to section 407(e), a NO_x emissions averaging plan would allow two or more units subject to the applicable emission limitations established pursuant to section 407 at 40 CFR part 76, to petition the permitting authority for alternative contemporaneous annual emission limitations for such units. Section 72.46 would specify the procedures by which a proposed NO_x emissions averaging plan would have to be submitted for approval, and some of the information requirements of the application. The Act states only in very general terms how the averaging relationship could be established and the parameters for an acceptable averaging plan. Since the emission limitations for NO_x and the rules for determining excess emissions of NO_x will be determined in the 40 CFR part 76 rules, the substantive requirements for an approvable averaging plan will also have to be specified in the 40 CFR part 76 rules.

a. *Applicable units.* The applicability section of today's proposal states that any unit that is an affected unit for NO_x during Phase I would be able to apply for NO_x emissions averaging during Phase I. The rule provides that only those units subject to a NO_x emission limitation under title IV could be included in an averaging plan. EPA requests comment whether only those units which are affected should be allowed to participate in NO_x averaging during Phase I. During Phase II, any unit that is an affected unit for NO_x under title IV of the Act may apply for this option.

b. *Common ownership requirement.* Units governed by a proposed nitrogen oxides emissions averaging plan would be required to have a common owner or operator in accordance with section 407(e) of the Act. If the units are located at more than one source they may be linked by a single compliance plan signed by multiple designated representatives. The Agency also considered whether to require that in addition to a common owner or operator, all units in a NO_x emissions averaging plan also must have a common designated representative. The Agency solicits comment on these interpretations of the common ownership requirement and, in addition, on whether the requirement could be met by requiring a common designated representative.

Section 72.46 also specifies the requirements and prohibitions that would apply to averaging plans, including the requirement that the designated representative and the owners and operators of the averaged units would share responsibility for ensuring compliance by all units with the plan, and liability for a violation at any or all units in the plan. The basis for this provision is discussed in the general section on compliance plans and in the section on designated representatives.

c. *Special annual compliance certification.* Today's proposal provides that the designated representative of any source with an approved NO_x emissions averaging plan may be required to include certain information in the end of year compliance certification in addition to the standard information required in § 72.400. This compliance information would identify all units in the NO_x emissions averaging plan and the combined emissions limitation for these units. It would also specify the total annual emissions of NO_x for each individual unit.

9. Phase I or Phase II Nitrogen Oxides Alternative Emission Limitations Plans

Section 72.47 of today's proposal would implement the NO_x alternative emission limitation compliance option authorized by section 407(d) of the Act. Under this section the designated representative for a unit subject to the NO_x emission limitation requirements of title IV of the Act and 40 CFR part 76, could request an alternative, less stringent, limitation, if a demonstration is made that appropriate control equipment, as specified in 40 CFR part 76, cannot meet the applicable limitation at that unit.

Today's proposal would specify the procedures by which a NO_x alternative

emission limitation application would have to be submitted for approval, and some of the information requirements of the application. The substantive criteria upon which the granting of such a request would be based and the remaining procedural requirements are proposed to be specified in the 40 CFR part 76 rules.

a. *Applicable units.* Section 72.47 of today's proposal specifies, in accordance with the Act, that this compliance option may be petitioned for during Phase I or Phase II by affected units subject to NO_x requirements during Phase I or Phase II, respectively according to the procedures specified in 40 CFR part 76.

b. *Technology requirements.* Today's proposal would, in accordance with the statutory authority, require that the determination to grant an alternative emission limitation must be based upon a showing, satisfactory to the permitting authority and the Administrator and in accordance with criteria to be specified by 40 CFR part 76, that the owner or operator: (1) Properly installed control equipment designed to meet the applicable 40 CFR part 76 NO_x emission limitation; (2) properly operated such equipment for a period of no less than fifteen months; and (3) provided operating and continuous emission monitoring data as specified in 40 CFR part 76 for such period demonstrating that the unit cannot meet the applicable NO_x emission limitation. In addition, the designated representative must specify in the application an alternative emission limitation that such unit could meet on an annual average basis.

Because such units would be unable to comply with the statutory requirement for a 15-month demonstration period, without first obtaining an operating permit, today's proposal specifies interim procedures by which a source may obtain a permit to demonstrate that a unit at that source cannot meet the NO_x emission limitation. Today's proposal presents a two-tiered application process: (1) An application for an alternative emission limitation demonstration period, and (2) an application for a final alternative emission limitation.

If a unit has properly installed and operated appropriate NO_x control equipment according to the conditions specified in 40 CFR part 76 for at least 6 months, and the monitoring data collected in accordance with 40 CFR part 75 demonstrates that the unit cannot meet the applicable NO_x emission limitation, then that unit would submit in its permit application, an application for an alternative emission limitation demonstration period. Based on this application, the permitting authority and the Administrator would designate (1) a demonstration period of not less than 15 months (which may incorporate retroactively some or all of the operating period prior to the date the application was submitted), and (2) an interim alternative emission limitation for the unit for the proposed demonstration period.

If by the permit application deadline the unit has not operated for a minimum of 6 months according to the procedures specified in 40 CFR part 76, the designated representative for the unit would not be authorized to submit a petition for an alternative emission limitation demonstration period in the permit application for that unit. Any such petition would have to be submitted as (1) an amendment to the permit application, if the Administrator had not yet acted upon the permit application, or (2) a modification or fast-track permit modification under subpart J, if the permit had been issued.

An alternative emission limitation may also apply to any unit for which the designated representative can demonstrate to the permitting authority and the Administrator, pursuant to 40 CFR part 76, that appropriate control equipment cannot be designed so as to meet the applicable limitation for that unit. In any such case, the designated representative would submit a petition, as specified in 40 CFR part 76, for an alternative emission limitation in the permit application for that unit. This alternative has been included in today's proposal to provide flexibility to utilities that know in advance of installation that appropriate control equipment cannot meet the applicable limit at a unit. Such utilities would be exempt from the requirement to install and operate the equipment before submitting an alternative emission limitation demonstration period application, if a demonstration can be made based on proven engineering design that such equipment could not meet the limit at the unit. The alternative would be to put such units in a double bind because the Act requires that in order to be granted an alternative emissions limitation the unit must demonstrate it has properly installed appropriate control equipment designed to meet the applicable limitation.

c. *Submission of applications.* The intent of the Agency in its interpretation of the NO_x alternative emission limitations provisions of the Act was to provide sources with adequate flexibility to enable them to take advantage of this provision where absolutely necessary, while not allowing frivolous applications which might undermine the goals for NO_x emissions reductions set forth in the Act. Of the four compliance options available to sources for complying with the NO_x emission limitations, the NO_x alternative emission limitations provisions would result in the most adverse environmental impact. For this reason, the Agency has included some features in today's proposal to ensure that the alternative limitation request is absolutely necessary and is a last resort, e.g., the requirement that a unit operate for a minimum of 6 months before requesting an alternative emission limitation. The Agency believes that this proposed requirement may have the practical effect of causing many sources to apply for a permit revision in order to be granted a demonstration period. Under these conditions, a source would probably not submit a frivolous application. This requirement would also ensure national consistency in the amount of data upon which a determination for the need for a demonstration period is based.

Approval of alternative emission limitations involves an evaluation of the equipment installed at a unit and of the operation of such equipment. This evaluation is comparatively more complex than the evaluations required for the approval of other compliance options. For this reason, the Agency is considering establishing a procedure for approval of alternative emission limitations during Phase II that involves the Administrator. Such a procedure would assist the States in their evaluation of requests for alternative emission limitations and assure consistent application of the requirements nationwide. The Agency requests comment on the inclusion of such a procedure in today's proposal.

Section 72.47(d) of today's proposal specifies the permitting authority's action on requests for NO_x alternative emission limitations. The Agency's specifications in this section mirror closely the statutory requirements of section 407(d) of the Act. The permitting authority's action on proposals for a demonstration period have been discussed above. Today's proposal would require the designated representative of a unit which has been granted a demonstration period to submit operating and monitoring data in accordance with 40 CFR part 76 which support the request for the final alternative emission limitation six months before the end of that demonstration period. The permitting authority would, then, take action on the final alternative emission limitation. Today's proposal would require that the

permit revision be a permit modification. This proposal is consistent with the Agency's treatment of permit revisions, a discussion of which can be found in subpart J of today's preamble.

As stated in the opening remarks of this section of today's preamble, most of the substantive requirements for NO_x alternative emissions limitation applications and determinations will be addressed in 40 CFR part 76.

10. Phase I Nitrogen Oxides Compliance Deadline Extension Plans

Section 72.48 would implement the provisions under section 407(d) of the Act which allow for an extension of 15 months of the Phase I NO_x compliance deadline. The intent of this provision is to alleviate a potential timing problem that may be faced by some sources during Phase I of the program. Specifically, Congress was concerned about the ability of sources affected in Phase I to comply on time due to the cumulative impacts of the following: (1) The limited number of vendors of low-NO_x burner technology, (2) the statutory schedule for promulgation of the NO_x emission limitations for affected units, and (3) the compliance deadline of January 1, 1995.

The NO_x compliance deadline extension would apply only during Phase I and only to the NO_x emission reduction provisions. Any unit which is an affected unit for NO_x during Phase I would be eligible to apply for the extension.

a. *Approach.* Today's proposal specifies, in accordance with the Act, that in order to be granted an extension the designated representative of the unit would be required to demonstrate to the satisfaction of the Administrator that the technology necessary to meet the applicable NO_x requirements is not in adequate supply to enable its installation and operation at the unit, consistent with system reliability, by January 1, 1995.

The substantive requirements for making such a demonstration will be specified in the 40 CFR part 76 rules. The procedures proposed today would require that the designated representative of a unit applying for the extension submit a list of the commercial vendors that have been contacted by the source, with certifications from these vendors that they cannot supply the appropriate control equipment for installation by January 1, 1995, including the date on which the owners, operators, or designated representative first solicited the equipment from each vendor.

To implement the statutory limitation on extensions where a utility is claiming an inability to comply with the January 1, 1995 deadline due to system reliability, utilities would be required to show that obligations to supply electricity could not be met due solely to the need to schedule shutdowns to install the NO_x control equipment. Today's proposal also specifies that the designated representative of any unit applying for an extension would be required to submit a vendor-certified schedule for equipment installation and related construction that delineates the dates of specific milestones, including the date on which the equipment will be operational. The Agency has included the above requirements to ensure that the source made a good faith effort to install NO_x control equipment in a timely manner.

Section 72.48 of today's proposal also describes the Administrator's action on proposed NO_x compliance extension plans. If the plan is submitted as part of the original permit application, the Administrator would take initial action on it within 3 months of receipt and final action within 6 months of receipt, as required by section 408. If the plan is submitted separately from the original permit application, the Administrator would be required to act on a proposed extension plan within three months of receipt as required by section 407(d).

11. Phase I or Phase II Opt-in Plans

Section 72.49 of today's proposal would require that permit application deadlines for opt-in units be those specified in 40 CFR part 74. EPA is reserving 40 CFR part 74 for purposes of implementing section 410 of the Act which allows sources that would not be affected in Phase I or Phase II to participate in the Acid Rain SO_2 program. Acid Rain requirements for sources that choose to opt-in to the program will be promulgated at 40 CFR part 74 in a later rulemaking.

12. Phase I or Phase II Common-Stack Plans

Section 72.50 specifies the proposed requirements for common-stack plans. When the emissions from units are ducted through and monitored in a common stack it is exceedingly difficult to reliably assign emissions to the individual units absent additional monitoring devices. In view of this concern, the Agency proposes in 40 CFR part 75 to treat affected units that share a common stack as one unit for purposes of calculating emissions, unless the source has installed, operated, and maintained continuous emission monitoring systems that satisfy the requirements in appendix A of 40 CFR part 75 in the ducts to the common stack for monitoring the emissions from each unit. When affected and non-affected units utilize a common stack, the owner or operator may also employ the procedures specified in § 75.11(a)(7) for determining the emissions from each of the affected units. In addition, the Agency has proposed to require one excess emissions offset plan under 40 CFR part 77, from affected units utilizing a common stack. Section 72.50, thus, proposes that units utilizing and monitoring in a common stack be governed by a common-stack plan submitted in accordance with 40 CFR parts 72 and 75. In addition, § 72.50 would require that, in the absence of a demonstration in the permit application that separate emission monitoring systems or procedures have been duly certified in accordance with 40 CFR part 75 for each unit, if any one unit using the common stack is not otherwise an affected unit it would have to be designated as an affected unit under the substitution, opt-in, or new unit provisions of subpart D, as appropriate. This would be a mandatory and necessary obligation in order to hold the source accountable for all emissions from the stack.

Thus, if the combined emissions exceed the aggregate of SO_2 allowances held for the units utilizing the common stack or the NO_x emission rate that would have been allowed under the applicable emissions limitation(s), all of the units using the common stack would be treated as being in noncompliance. Moreover, since it is exceedingly difficult to assign or apportion emissions to the individual units using one monitor at a common stack, the owners and operators of all the units with emissions ducted to the stack would share responsibility for ensuring compliance with any excess emissions penalties and offset requirements.

F. Acid Rain Permit Contents

Subpart E describes the content requirements of all Acid Rain permits, including general information, designated representative certifications, prohibitions, the incorporation of Acid Rain program definitions, allowance information, compliance plans, monitoring requirements, and reporting and recordkeeping requirements. These requirements are mandated by the statute or are necessary to ensure that the permit provisions are enforceable and will achieve the emissions reductions required by the Act. Each permit would specify the annual basic and bonus allowance allocation for each unit because if the allowance system were to fail, the annual emissions limit

for each unit would be that unit's annual allowance allocation.

The Acid Rain permit content requirements would apply to all Phase I and Phase II Acid Rain permits, whether those permits were issued by EPA or by a State or local permitting authority with a program approved under Title V. The purpose of the Acid Rain permit is to provide a document where all of the Acid Rain requirements that apply to an individual source, and to each unit at the source, are articulated. This would provide certainty to the source, the permitting authority, and the public regarding exactly what requirements the source is subject to under the program.

1. Permit Shield

This subpart would also address the "permit application shield" and "permit shield" effects of permit submissions under the Acid Rain program. Section 72.53(a) would, consistent with section 503(d) of the Act, shield any source which has submitted a timely and complete permit application, from any possible liability under section 502(a) of the Act for operating without a permit, where the source's failure to have a permit is the result of inaction on the part of the permitting authority and no fault of the source. The application shield would also apply where an affected source operates in compliance with an approved permit application and compliance plan binding on the source prior to the permit's effective date.

In addition, consistent with section 504(f) of the Act and § 70.6(h)(1) of the proposed title V regulations, § 72.52(b) of today's proposal would shield any source operated in accordance with a permit properly issued under title IV and 40 CFR part 72, from enforcement. The provision would give certainty to affected sources operated in compliance with the terms of a properly issued permit that they would no longer be subject to other requirements of the program that might otherwise apply. For example, a unit governed by a properly approved repowering extension, would no longer be subject to the January 1, 2000 Phase II compliance deadline.

Section 72.52(b) would, however, limit the shield that is being proposed by the Agency under section 504(f) at § 70.6(h)(1). Specifically, as required by section 408(h)(2) and as authorized by section 504(f), EPA proposes that a source would not be shielded by a provision of a permit that does not clearly comply with the requirements of title IV or the Acid Rain program, including any provision in a title V permit or State decision interpreting a title V permit in a manner that would alter the applicability of a title IV requirement to a source. The Agency interprets the language in section 504(f) authorizing such limitations on the shield and the limiting language in section 408(h)(2) as a protection against permit conditions, including conditions resulting from a State interpretation of a permit provision, that would alter essential Acid Rain program requirements such as the requirements governing designated representatives, emissions monitoring, recordkeeping, and reporting, approval of compliance options, and liability. The Agency requests comments on the permit shield provisions in today's proposal.

G. Acid Rain Phase I Implementation

1. Description of Process

Subpart F describes the proposed implementation of the Phase I Acid Rain permit program. The units covered under Phase I of the program, listed in appendix A, generally include the largest plants with the highest SO_2 emissions in the United States. In addition, certain other units may become affected units in Phase I of the program under one or more of the compliance options provided in subpart D. Title IV of the Act mandates that SO_2 and NO_x emissions reductions for Phase I affected units begin on January 1, 1995 and continue in effect until December 31, 1999. While the Phase I emissions reduction obligations begin on January 1, 1995, some Phase I requirements begin earlier.

Title IV requires that Phase I permitting be implemented by EPA. The Agency will process permit applications, write and issue permits, and process permit revisions. In addition, in cooperation with State and local air quality agencies, EPA will monitor compliance and take appropriate enforcement action as necessary. In contrast, permitting for Phase II of the Acid Rain program, which begins January 1, 2000, will be implemented by States with approved operating permit programs under title V of the Act, and by EPA only for sources in States where an operating permit program has not been approved. This subpart includes the proposed deadlines and procedures for the Phase I permit program only.

Consistent with section 408, the basic permitting process for Phase I would be as follows: The designated representatives for Phase I affected sources would be required to submit Acid Rain permit applications and proposed compliance plans to the Agency on or before February 15, 1993. (Designated representative certifications under subpart B, would have to be filed for each Phase I affected source not later than with the permit application.) The Agency would review and act on these applications, using the procedures set forth in subpart G including an opportunity for public comment, within 6 months of receipt. (For sources applying on February 15, this would be about August 15, 1993; earlier applications would receive earlier attention.) The rule would afford sources and persons who commented on proposed permits an opportunity to appeal permitting decisions (using the procedures set forth in subpart H). The appeals would have to be filed within 60 days of the Agency's decision; thus, ensuring that disputes will be resolved prior to the emissions reduction requirements that begin on January 1, 1995.

2. Treatment of Effective Date of Permits

Section 408(a) of the Act specifies that Acid Rain permits have a term of five years, but section 408(c)(2) requires EPA to act on compliance plans by August 15, 1993. EPA believes that the clear intent of Congress was for Phase I Acid Rain permits to remain in effect for the 5-year duration of Phase I. Thus, the Agency is proposing to issue Phase I permits on or about August 15, 1993, and to have those permits take effect on January 1, 1995. This interpretation of the statutory deadlines would ensure that the Phase I permits will not expire in the middle of Phase I.

The rule would also clarify what requirements apply to the source prior to the permit's effective date. Specifically, the permit application and compliance plan would be binding on the source upon a determination of completeness until the permit became effective. EPA could, thus, ensure compliance by the source with monitoring and other Acid Rain requirements that must be met before January 1, 1995. EPA's authority to approve, disapprove, or modify permit applications and compliance plans would afford further protections.

The Agency believes that the proposed approach to the permit term and effectiveness issue best reflects the intent of Congress. It allows permittees and interested parties the flexibility to contest Acid Rain permit conditions before commencement of Phase I emissions reduction requirements, reduces the potential burden of redundant permitting, yet ensures that essential program elements will continue to be in place.

H. Federal Acid Rain Permit Issuance Procedures

1. Approach

This subpart describes the proposed issuance procedures for Federal Acid Rain permits. The authority for the permitting procedures set forth in this subpart can be found in section 408(a) of the Act, which mandates that the provisions of the title IV be implemented by permits issued to affected units in accordance with the provisions of title V (40 CFR parts 70 proposed at 56 FR 21712, May 10, 1991, and 71), as modified by title IV. These procedures are intended to be as consistent with 40 CFR parts 70 and 71 as possible, while addressing the particular permitting concerns of the Acid Rain program. The Agency requests comments on coordination of this subpart with the operating permits program. EPA also requests comments on the coordination between requirements in this subpart which apply to State Acid Rain permitting programs (40 CFR part 72, subpart I) and the State operating permits program set forth at 40 CFR part 70.

Title V of the Act is largely based on the Agency's existing Clean Water Act permitting program, the National Pollutant Discharge Elimination System (NPDES). Congress believed the NPDES program was relatively successful in reducing pollutants in the waters of the United States, and used the NPDES program as a model for Clean Air permitting. In keeping with Congress' intent to base Clean Air permitting programs on existing Agency permitting programs, this subpart is modeled in large part on the consolidated permitting procedures set forth at 40 CFR part 124. The part 124 procedures are used for the NPDES program, the Resource Conservation and Recovery Act (RCRA) permitting program, and the Prevention of Significant Deterioration (PSD) air permitting program. The Agency believes that it is preferable to build on these existing procedures, rather than developing completely new permitting procedures. While 40 CFR part 124 is used as the basis for today's proposed procedures, the Agency has made modifications to those procedures to ensure consistency with Title V, to address the particular concerns of Acid Rain permitting, and to modify aspects of the 40 CFR part 124 procedures which have not worked effectively in these other permitting programs. Thus, while the procedures set forth in today's proposal are similar to those in 40 CFR part 124, they are not identical. The Agency requests both overall comments on the procedures in today's proposal and comments on specific aspects of the proposed procedures.

The permit issuance process proposed in this subpart is as follows: the permit writer would determine whether the application and compliance plan submitted by the designated representative is complete. After all additional information has been obtained, the permit writer would prepare a proposed permit and an accompanying statement of basis, which would describe the legal and factual basis of the permit requirements. Public notice would be provided on the proposed permit, and the public would have an opportunity to comment and ask for a public hearing.[16] Following submission of all comments, the permit writer would revise the proposed permit based on the comments. The revised permit would be issued as the permitting decision, after which appeals to the permit may occur.

2. Regional Role

The proposal would require that copies of all Acid Rain program filings be sent simultaneously to the State, to the EPA Regional Air Program Division, and to the EPA Headquarters, Acid Rain Division. The date of receipt of permit submissions would be determined by the date of receipt at the appropriate U.S. EPA Regional office. This proposal does not, however, articulate whether the Regions or Headquarters will issue the Phase I permits, and Phase II permits where the State defaults, or whether the Regions will have a role in Acid Rain permit appeals. Instead, the proposal uses the term "Administrator". EPA's current thinking is that the Agency would employ a team approach in taking any Federal permit action during which the EPA Regional office, EPA Headquarters office, and the State would work together. The Regional office would, however, maintain the official record of permit actions and would officially issue the permit.

Traditionally, implementation of Federal environmental permitting programs has been delegated to the Regions. Such an approach is logical since the Regions are more familiar with the sources. The Regions also would be responsible for reviewing State permit programs beginning in 1993 for consistency with the Acid Rain program, and for reviewing proposed State-issued operating permits in Phase II. Similarly, administrative challenges to EPA actions are traditionally heard in the Regional Offices, with the Administrative Law Judge's office operating a circuit managed by the Regional Hearing Clerks. This is particularly appropriate since the record of a permit action and information about the source is located in the Regional Office. Thus, the Regions will undoubtedly play a critical role in the Acid Rain program. Certain permit actions might, however, require a Headquarters lead to improve national consistency in Acid Rain permitting requirements.

I. Appeal Procedures for Acid Rain Permits

Subpart H describes the proposed rights and procedures for administrative appeals of permitting decisions of the Administrator under the Acid Rain program.[17] Subpart H also lists other Acid Rain program decisions of the Administrator that are not "permitting decisions" and, therefore, not subject to the procedures of subpart H even though they may ultimately be incorporated into the Acid Rain program permit provisions applicable to the source. These include any action by the Administrator relying on a certificate of representation submitted under subpart B; any action by the Administrator regarding a proposed excess emissions offset plan under 40 CFR part 77; or any action by the Administrator on a proposed alternative emissions monitoring system under 40 CFR part 75. The Agency is, however, considering whether all decisions by the Administrator under the Acid Rain program pursuant to 40 CFR parts 72–78 should be subject to an appeals procedure such as is proposed today.

Section 307 of the Act provides an opportunity for judicial review of final Agency action under the Act in Federal circuit court. Such judicial review is available after the petitioner has exhausted all administrative remedies, such as administrative appeals procedures. Use of an administrative appeals procedure is consistent with other environmental permitting programs, including the NPDES, RCRA, and PSD programs. An administrative appeals procedure is, moreover, appropriate since it would allow the Agency to review permitting decisions

[16] In its public notice, the Agency will provide a phone number or method of access to an electronic bulletin board to ensure the public can obtain information on whether a hearing will be held on the proposed permit, and the time and location of any scheduled hearing.

[17] The term "permitting decision" is defined in § 72.2 as any permitting action taken by the Administrator under the Acid Rain Program following the administrative procedures of 40 CFR part 72, including where provided for, an opportunity for public comment. (See, also definitions for "proposed permit.")

for correctness before having to defend permitting actions in Federal court. This approach would also provide petitioners with a less resource intensive (and less time-consuming) process for resolving disputes concerning Acid Rain permit conditions, than would be involved in a judicial action.

The administrative appeals procedures proposed in subpart H are guided by two concerns: (a) The need to expedite the appeals process (particularly since an opportunity for public comment would have already been provided before any permitting decision was reached), and (b) the need to provide a forum for resolving factual disputes if necessary in any final review by the Administrator.

The rule would allow appeals of decisions by the Administrator on the basis of factual, legal, or policy issues. The rule would include limited opportunity for an evidentiary hearing to resolve disputes concerning genuine issues of material fact. Specifically in reviewing any appeal involving disputed issues of fact, the Administrator would have the option of referring the case to a Presiding Officer (see definitions) appointed by the Chief Administrative Law Judge to conduct an evidentiary hearing. If permit issuance responsibility is delegated to the Regions (see discussion of subparts F and G), the Agency proposes that such appeals would be heard in the Region in which the affected unit is located.

The rules and procedures proposed today for conducting evidentiary hearings are based on the procedures used for permit appeals in the NPDES program, and on the Federal Rules of Civil Procedure. To ensure expedition, Presiding Officers would be required to: limit evidentiary hearings to genuine issues of material fact, limit evidence to such factual issues, and bar testimony on legal and policy issues. The Presiding Officer would, moreover, be authorized to limit the hearing to a paper evidentiary hearing where direct- and cross-examination of witnesses would not be necessary for a full and true disclosure of the facts. This is appropriate since permitting is an essential rulemaking function and, as previously mentioned, there would already have been an opportunity for public comment.

The rule proposes that the standard of review to be applied by the Administrator and Presiding Officer be as follows. The person seeking a permit would bear the burden of proof that the permit should be issued. Any person challenging the permitting decision would bear the burden of going forward and showing that: (1) with regard to any factual finding or legal conclusion underlying the permitting decision, the standard is "clearly erroneous"; and (2) with regard to an exercise of discretion or a policy determination underlying the permitting decision, the standard would be "arbitrary and capricious". These standards are consistent with the traditional standards for reviewing actions of agencies under the Administrative Procedures Act.

After a petition for review is filed, the Administrator would grant or deny the petition and have the option to refer the petition to a Presiding Officer for evidentiary hearing. If the petition for review is granted and an evidentiary hearing is not granted, the parties may file briefs. The Administrator would, thereafter, issue a final order addressing the appealed issues. The order, supplemented by the record of the appeal and of the decision, would become the final Agency action.

If the case is referred to a Presiding Officer for hearing, the Presiding Officer's review would conclude with a proposed order. The proposed order would become a final Agency action, unless (a) the Administrator issued a notice of intent to review within 30 days, sua sponte; or (b) a party filed a further appeal to the Administrator objecting to the proposed order within 15 days and the Administrator issued a notice of intent to review the proposed order pursuant to the objection. An appeal of a proposed order to the Administrator would have to allege that a finding of fact or conclusion of law was clearly erroneous, or that an exercise of discretion or a policy determination was arbitrary and capricious. In issuing a notice of review, the Administrator would have discretion to allow briefs by the parties.

The Agency has proposed this approach because it would allow for full development of factual disputes during the administrative review process. It would afford the Agency an opportunity to correct erroneous factual determinations, and ensure that the permit writer appropriately applied the regulatory and statutory requirements to the site-specific circumstances of the source. This approach would also allow the Agency to fully consider the legal and policy implications of a permitting decision, prior to any judicial review.

1. Other Approaches Considered

The Agency also considered proposing permit appeals procedures that would not afford any opportunity for a hearing. Such an approach is used in the RCRA and PSD programs which do not provide for evidentiary hearings, where challenges to permitting decisions are filed with the Administrator. The Agency considered whether such an approach might be appropriate here since: the permit decision would have been reached following a full opportunity for public comment, and evidentiary hearings can be resource intensive. The Agency believes, however, that allowing a procedure for a full airing of factual issues would ultimately reduce delays in the permitting program. This is particularly the case since factual hearings could help expedite reviews by the Administrator, and since the absence of a hearing procedure could increase the risk of judicial remands to the Agency for further development in cases alleging genuine issues of material fact. In addition, using an evidentiary hearing process the Administrator would have a more complete record to review concerning any factual issues than if he or she were to make a decision based solely on the permit issuance record. Thus, an administrative proceeding which only allowed for an appeal to the Administrator would not necessarily be more expeditious. The proposed procedure would, thus, tend to remove any doubt that decisions accurately reflect the policies of the Agency.

Perhaps the strongest criticism of an evidentiary hearing process is the time involved in an appeal. Today's proposal, therefore, would not only limit hearings to cases where they are really necessary, but would also establish deadlines for parties' submissions and for certain Agency actions. The proposed limitations and deadlines would speed evidentiary hearings and, thus, reduce the burden of hearings on the Agency, on permittees, and on parties seeking to appeal permit conditions. The Agency requests comment on whether to provide for an evidentiary hearing process or an abbreviated process similar to that used in the RCRA and PSD programs for appealing initial decisions of the Administrator.

J. Acid Rain Phase II Implementation

Subpart I sets forth the permitting requirements for Phase II of the Acid Rain program.[18] Unlike Phase I, section

[18] Phase II emissions reductions begin on January 1, 2000 following the conclusion of Phase I. Some other Phase II requirements begin earlier (*e.g.* emissions monitoring, and schedules for sources applying for repowering extensions). In Phase II, the remaining affected units that were not regulated in Phase I, *e.g.*, those listed in appendix B of today's proposal, will be subject to Acid Rain Program emissions reduction requirements. New units and units that "opt in" under the terms of 40 CFR part 74 will be regulated as well.

408 requires that Phase II permitting be implemented by States with operating permit programs approved under 40 CFR part 70 by July 1, 1996. In the event a State's permit program has not been approved in time under 40 CFR part 70, EPA would implement the Acid Rain permit requirements for affected sources in that State in accordance with 40 CFR part 71 and this part. (The process for Federal permitting of Phase II requirements would be the same as for Phase I and for other Federal permit issuance under 40 CFR part 71 in instances of State defaults under 40 CFR part 70.) In some cases, a State may obtain 40 CFR part 70 program approval after July 1, 1996, but before the EPA has issued initial Phase II permits to all of the Acid Rain sources in the State. Some States may have relatively few Phase II Acid Rain sources to begin with. The EPA, thus, proposes to reserve the right to delegate responsibility for permit review and implementation to such a State, potentially including permit issuance for all unpermitted Acid Rain sources, if EPA determines that such a delegation would not result in undue burden for the permitting authority or delay.

Pursuant to the schedules and procedures of title IV, subpart I would require affected sources to submit Phase II permit applications and proposed compliance plans for SO_2 by January 1, 1996, for NO_x by January 1, 1998, and for new units twenty four months before the latter of January 1, 2000 or the date the unit "commences operation". Copies of each application would have to be sent to the State, to EPA Headquarters, and to the Region.

Subpart I provides that the State with an approved program would make a determination of completeness in accordance with 40 CFR 70.5(c), and would notify the Administrator of such determination.[19] The permitting authority then would write a "draft permit" (See, § 72.2 definitions) and allow opportunity for public comment in accordance with section 502(b)(6) and proposed 40 CFR part 70(i). Following the public comment period, the State would submit a "proposed permit" to EPA for review. Following EPA review, and assuming EPA did not veto the proposed permit as provided in proposed Section 70.8, the Acid Rain permit would be issued. Section 408 mandates that Phase II SO_2 permits be issued by States on or before December 31, 1997. As is discussed above regarding subpart E, applications would be binding on sources before the permit is issued.

The schedule mandated by title IV for issuing initial Phase II Acid Rain permits coincides roughly with the first two years for States to complete issuing original permits under title V and proposed 40 CFR part 70. Pursuant to title IV, State permitting authorities are required to issue permits for Phase II SO_2 requirements by December 1997. Pursuant to title V, within four years after a State receives EPA approval of its title V permit program it must complete the process of issuing title V permits covering all Clean Air Act requirements to all sources in its jurisdiction. Thus, under today's proposal the Acid Rain program Phase II SO_2 requirements would appear as a separate section of the operating permit issued to an affected source under title V and 40 CFR part 70.

With regard to the title IV NO_x permitting deadlines, applications are not due until January 1, 1998. Thus, where a source did not file its NO_x limitation application with its Phase II SO_2 permit application in 1996, the State would have to reopen the previously issued permit "for cause" to add the pertinent NO_x provisions. Similarly, if a title V operating permit covering SIP requirements were issued to a source under 40 CFR part 70 before the deadline for sources to submit, or for States to act on, Acid Rain Phase II SO_2 permit applications, the State would have to reopen the title V permit "for cause" to incorporate the Acid Rain SO_2 requirements. As is discussed further below, permits for affected sources are required by section 408 to have a fixed term of five years. To prevent permit cycle problems, States would be required by 40 CFR parts 70 and 72 to put affected sources on a 5-year cycle for all permitting requirements.

1. Appeals of State Issued Permits

Consistent with 40 CFR 70.4(b)(3)(x) and section 502(b)(6) of the Act, appeals of Acid Rain provisions in State-issued permits would occur through State administrative and judicial appeals procedures. The Agency believes this requirement is appropriate since the expression of Congressional intent in section 502(b)(6) that States undertake these functions is clear. In addition, with the exception of matters constituting actions of the Administrator (See discussion below), the State will have made the permitting decisions which will be considered on appeal. Furthermore, the Acid Rain requirements will be only one portion of the State-issued operating permit applicable to an affected source, and other operating permit provisions may also be at issue in any appeal.

Decisions of the Administrator that are incorporated into State issued Acid Rain permits would, however, be subject to the administrative appeals procedures set forth at subpart H, and to judicial review in Federal circuit court pursuant to section 307(b)(1) of the Act which provides an opportunity for Federal court review of "final actions of the Administrator". Decisions of the Administrator that must be incorporated into the source's operating permit include: acceptance of a designated representative certification and issuance of a designated representative identification number, approval of a monitoring plan, certification of a monitoring system and or of an alternative emissions monitoring system under 40 CFR part 75, approval of an excess emissions offset plan under 40 CFR part 77, and determination of whether a proposed technology meets the criteria for a repowering extension under subpart D. The Agency believes that such decisions of the Administrator should be appealed federally rather than through State procedures because: (1) The State was not involved in making the decision, (2) a Federal review procedure for these decisions will help ensure a nationally consistent body of judicial precedent, and (3) as final Agency action, the decisions will be reviewable in Federal rather than State court. The Agency is, therefore, proposing that decisions of the Administrator that are incorporated into the Acid Rain portion of a State permit be subject to Federal administrative, and (upon becoming final) Federal judicial appeal procedures if challenged. This is consistent with statutory authority, as any final decision of the Administrator is reviewable in Federal court under section 307(b)(1) of the Act, and is therefore not appropriate for State court review. State court actions in such cases is preempted.

In addition, § 72.202 of today's rule proposes Acid Rain-specific criteria for approving State operating permit program approval. These criteria, which would ensure adequate notice and opportunity for EPA to participate in challenges to Acid Rain permit provisions during Phase II, include:

[19] The permit application and proposed compliance plan are binding on the source prior to permit issuance. (See § 408(d)(3).) The Agency is proposing that the application and proposed compliance plan be binding upon submission to the permitting authority. The Agency believes, however, that a disapproved or incomplete application should not be binding because it does not meet the applicable requirements of the Act. The rule proposes that the State inform EPA if any completeness determination in order to know whether the application is binding on the source and enforceable.

• Providing actual notice to EPA of administrative or judicial proceedings at the State level concerning an Acid Rain provision of any permit;

• Providing actual notice to EPA of any order or decision issued following a State administrative or judicial proceeding that interprets, modifies, voids, or otherwise relates to any portion of an Acid Rain permit. (Following any such decision, EPA would have an opportunity to review the permit pursuant to 40 CFR 70.8);

• Authority effectively granting EPA the right to intervene in any administrative or judicial appeal before the State involving an Acid Rain permit provision;

• Limitations to ensure that no appeal concerning an Acid Rain permit provision will result in a stay of any such provision, except as provided in § 72.95.

These criteria are specified to help ensure nationally consistent implementation of the Acid Rain program. As has been discussed elsewhere in today's proposal, national consistency is necessary to ensure an active allowance market that is not hindered by local inconsistencies in Acid Rain implementation. The actual notice requirements will ensure that EPA has an opportunity to become involved in a State level appeal, and that decisions interpreting Acid Rain permit provisions in a manner that is inconsistent with the national implementation of the program will be treated as proposed permit modifications subject to review by the Agency. Affording the Agency the right to intervene in any State administrative or judicial appeal of an Acid Rain permit provision in order to inform the State agency or court on any issues of concern to the Acid Rain program as a whole would further help ensure a nationally consistent program. In addition, a right of intervention would afford EPA a clear opportunity to seek removal to Federal court of any proceeding that might raise a question of Federal law by interpreting Acid Rain requirements in a way that is significantly inconsistent with the national program.

The Agency also believes that it is in the interest of the States to provide these opportunities for Agency participation in challenges to Acid Rain permit provisions. A State administrative or judicial proceeding could inadvertently result in interpretations of Acid Rain requirements inconsistent with the national Acid Rain program. This interpretation could bind the State permitting authority when issuing subsequent Acid Rain permits. The Agency would have to veto each such permit and possibly revoke approval of the entire operating permits program until the problem was remedied. The Agency believes that such an outcome would be far more intrusive and detrimental to the State and EPA than the approach proposed today.

The Agency also proposes to require that State appeals procedures include the limitations on stays of Acid Rain permit provisions specified at § 72.95. The Agency believes that these limitation provisions are essential to the proper functioning of the Acid Rain program and is, therefore, proposing today to require States to include these provisions in their regulations as a precondition to receiving approval of an operating permits program. This section disallows stays of standard permit provisions that are mandated by title IV and the Acid Rain program regulation, or of provisions that are essential to the functioning of the Acid Rain program. This requirement is designed to ensure that appeals are not brought by sources seeking to escape from the Acid Rain requirements of the Act, and to protect sources from challenges brought by other "interested persons" for the purpose of pressuring the source to meet demands that may or may not be related to the Acid Rain program or risk non-compliance because of stays of, for example, an extension, during an appeal.

The Agency requests comments on this approach and on the extent to which States already have the legal authority to comply with the State program approval criteria specified above.

2. Permit Term

Title IV mandates that Acid Rain permits be issued for terms of 5 years. The Agency is proposing that Phase I permits (which will be issued in 1993) be effective from January 1, 1995 through December 31, 1999 to coincide with Phase I. In addition, the Agency seeks comment on three options for integrating title IV Phase II and title V permit issuance.

Under one option States would schedule all title V permitting for affected sources so that the effective date of the Phase II permits would run from January 1, 2000 to 2005. Under this approach the State would "issue" the permit in 1997 as required by statute, but the permit would have a delayed effective date. The State would reopen "for cause" the already-existing EPA-issued Phase I permit to add other Clean Air Act requirements, such as SIP limitations. This combined permit would expire on December 31, 1999, five years after the date on which the Phase I permit originally became effective (January 1, 1995). In addition, the State would concurrently issue a second title V permit to the source. This second permit would be effective from January 1, 2000 through December 31, 2004, and would include all applicable Clean Air Act requirements (e.g., SIP or NSPS requirements and Phase II Acid Rain requirements). Under this approach only one title V permit would be effective at any given point in time. This approach would be consistent with the approach proposed for the Phase I permit cycle, but has several drawbacks. First, the approach will only be available for those affected sources that were regulated, and issued permits by EPA, in Phase I. This is only a small fraction of the total number of sources which must be issued permits for Phase II.[20] In addition, some Phase II requirements begin before the year 2000. For example, sources choosing to repower must notify EPA of their intent by December 31, 1997. In addition, all Phase II sources must have their emissions monitors certified by January, 1995. Ideally those requirements should be incorporated into the permit for the source. If the Phase II permit has a delayed effective date, the requirements would have to be added to the Phase I permit.

Thus, for many sources, delaying the permit's effective date until January 1, 2000, would not be practical and delaying the effective date of the Phase II permit until January 1, 2000, would not result in any resource savings for the source or the permitting authority. The Agency, therefore, recommends that the States endeavor to issue Phase II Acid Rain permits on the same cycle as other permitting for the source.

Under the second and recommended option the State would issue all title V operating permits to affected sources by no later than December 31, 1997, as in option one. But, unlike option one, the State would not reopen the original EPA-issued Phase I permit. Instead, it would issue a separate title V permit that would become effective immediately upon issuance in 1997 and would remain effective for five years, through 2002.

This separate permit would not include or address in any way any of the Acid Rain Phase I requirements covered by the EPA-issued permit, but would

[20] There are 110 sources which must obtain permits for Phase I of the Acid Rain program. Some as yet unknown additional number of sources will have to obtain Phase I permits if they have substitution or compensating units (See discussion of subpart D). Over 1000 affected sources will be subject to Phase II.

contain all the Phase II Acid Rain requirements as well as all other Clean Air Act requirements (e.g., SIP limitations and other title V specific permit requirements). Thus, although both the EPA-issued Phase I permit and the State-issued initial Phase II permit would be in effect during a short period of overlap (1998 and 1999), all requirements that must be met by the source will thereafter be contained in one permit document.

Under a third option States and sources would be allowed flexibility to rely on one of the two approaches just discussed, or to adopt some other approach. The only constraint would be that any approach adopted by the State would have to conform to the permitting deadlines in both titles IV and V. Under this option the State permit program approval criteria in § 72.202 would include a requirement that the States propose the approach they intend to use to integrate the title IV—title V permitting requirements when submitting their permit programs to EPA for approval.

The Agency requests comment on the three integration approaches, and whether any one approach should be mandated in the final rule.

The subpart I regulations are designed to ensure that when the States issue the Acid Rain portion of operating permits to affected sources within its jurisdiction, the goal of national regulatory consistency among all Acid Rain permittees will be met. The Agency recognizes, however, that the State will issue an Acid Rain permit as a component of a larger operating permit. To the extent possible, the regulations are structured to allow a State to issue the permits in a manner consistent with the permit issuance procedures that will be in place under an approvable title V program. The regulations seek to achieve the goal of minimal State administrative disruption by relying, whenever possible, on the title V regulations proposed at 40 CFR part 70. The Agency invites public comment on whether there are unnecessary inconsistencies between the proposed title IV and V regulations and solicits comments on specific ways of improving coordination and consistency to the extent possible.

3. State Program Approval Criteria

Subpart I includes the Acid Rain program criteria that would have to be met by any State seeking EPA approval of an operating permit program under title V of the Act and 40 CFR part 70. It provides, first, that the Administrator will withhold or withdraw approval of a permitting program submitted under 40 CFR part 70 if the program authorizes any measure, or is implemented in a manner, that would interfere with the Acid Rain allowance program. Measures or implementation that would constitute such interference, and are thus prohibited, include but are not limited to:

• Prohibitions on the acquisition or transfer of allowances by an affected unit located in the State or area under the jurisdiction of the permitting authority;

• Restrictions on an affected unit's ability to sell or otherwise transfer allowances;

• Requirements that an affected unit maintain a reserve of allowances over and above those necessary for purposes of prudence;

• Failing to notify the Agency of any State-level appeals to, or decisions covering Acid Rain permit provisions, that might affect Acid Rain program requirements;

• The issuance of orders by the permitting authority inconsistent with title IV interpreting Acid Rain program requirements as not applying to a source in whole or in part, or otherwise modifying the requirements; or

• Any other measure that the Administrator determines would hinder the flexible operation of the Acid Rain allowance program.

In addition, to ensure national consistency in the Acid Rain program implementation, § 72.202(i) provides that State permit programs would not be approvable unless they:

• Provide for notification to the Agency in the event of a permit appeal under section 502(b)(6) of the Act that might affect Acid Rain program requirements;

• Impose a time bar that limits when appeals of Acid Rain permit provisions can be brought;

• Authorize Agency intervention in any State-level permit challenge as a matter of right; and

• Require submission to the Agency, as a proposed permit modification subject to § 70.8 review, of any determination by the State interpreting any permit requirement in a manner that might change or void the requirements.

The Agency believes that these criteria are necessary to ensure that States do not inadvertently interfere with nationally consistent implementation of the Acid Rain program. The rule provides further that EPA will revoke a permit "for cause" in the event of any administrative or judicial State determination concerning the permit that is inconsistent with title IV of the Act and 40 CFR parts 72–78.

In addition, § 72.202(b) of the proposal provides that the Administrator will withhold or withdraw approval of any permit program, if the permitting authority interferes with the Administrator's decision regarding an excess emissions offset plan. The goal of the Acid Rain program is to achieve national reductions in the total loadings of SO_2 and NO_x while allowing sources maximum flexibility in determining least-cost methods of compliance. To ensure that actual reductions occur, the statute provides for stringent excess emissions offsets and penalties. These offsets and penalties are designed so that emitting beyond the number of allowances held will never be cost-effective for a source. This enforcement authority counterbalances the incentive program provided by allowance trading, and should not be undermined by inconsistent State enforcement. Therefore, the Agency is proposing to limit the States' authority to interfere with Agency decisions regarding excess emissions offset plans.

The Agency also plans to ensure national consistency by requiring the permitting authority to use standardized forms or the Acid Rain Program Electronic Permitting System for Acid Rain permit applications and compliance plans, permits (including standard conditions), designated representative certifications, and compliance certifications. Use of these forms or the computerized permitting system will help to ensure nationally uniform implementation of the permitting requirements, and to prevent the increased costs that would be associated with the imposition by States of additional Acid Rain permitting requirements. The Agency believes that this requirement will facilitate the allowance market because all sources, no matter where they are located, will be subject to the same requirements.

The Agency requests comments on these criteria for State program approval.

K. Permit Revisions

Subpart J specifies the procedures that would apply for revising Acid Rain permits. The rule proposes that permit revisions would become effective upon approval in accordance with the procedures specified in subpart J. This is to ensure that no proposed revision could be used to insulate a source from the obligation to comply with a permitted requirement, and to provide clarity regarding what applies to a source at any given point in time.

Generally, the proposed rule tracks the permit revision requirements in

proposed § 70.7, which would apply to State permitting programs under title V of the Act and 40 CFR part 70. The title V rules propose three types of permit revisions: permit modifications, minor permit amendments, and administrative permit amendments. Subpart J of today's proposal specifies how various types of changes to Acid Rain permits would fall into the 40 CFR part 70 categories of revisions. It also proposes an additional category of automatic permit amendments, and proposes a procedure to expedite the permit modification process.

1. Prohibited Revisions.

The rule ensures that certain Acid Rain permit provisions cannot be modified. For example, notwithstanding any changes a source makes in its method of compliance, each unit must hold enough allowances in its Allowance Tracking System account to cover its SO_2 emissions for the year. This requirement cannot be revised. Other standard provisions would similarly not be subject to any possible revision.

2. Modifications.

Today's proposal specifies that, within the 40 CFR part 70 structure, the Acid Rain program would apply permit modification procedures to changes such as the addition of a new compliance option that the source did not submit to the permitting authority with the initial permit application for review and comment during the permit issuance process, and that involves a unit at a source that was not previously affected and subject to the Acid Rain permit's requirements.[21] The Agency also proposes to use the permit modification procedure (or a variant allowing fast-track modifications as discussed further below) for revisions to a previously approved compliance plan that involve units not previously governed by the plan.

The Acid Rain compliance option is a fundamental component of the permit. Certain changes in the compliance option, such as those described above, have significant implications for allowance allocations, on emissions levels, and sometimes, on unit coverage under the program. Thus, the Agency believes that certain significant changes to compliance options must not occur without an opportunity for review and public input where appropriate. Where, however, a new or revised compliance option does not involve a unit not previously affected, for example, a new reduced utilization plan relying on energy conservation measures where no compensating unit is designated, the permit modification procedure would not apply.

In addition, §§ 72.300(e) and 72.301 provide that a State decision interpreting an Acid Rain program permit provision in a manner that effectively modifies or voids a program requirement would be deemed a proposed permit modification by operation of law. As with any proposed permit modification by the State during Phase II, such an interpretation would be subject to Agency review pursuant to § 70.8 of the title V rules. Under 40 CFR part 70 public comment and Federal oversight, as required for original permit issuance, would be required for modifications except that such comment and oversight would cover only the proposed permit changes, rather than the unchanged activities at a source.

The Agency believes that an expedited procedure is appropriate to allow for permit modifications in a manner that will provide sources with the flexibility to make needed changes in a timely manner. Without such a procedure sources would have to follow the more burdensome modification procedures discussed above and specified in 40 CFR part 70. Today's proposal, therefore, includes a separate "fast-track" modification procedure, at § 72.302, which could be used at the option of the source in lieu of the modification procedure of § 72.301, for example, (1) where an affected source wishes to change its method of compliance with the Acid Rain program requirements to an Acid Rain compliance option under subpart D which it did not submit for approval and comment during the permit issuance or reissuance process and which, in the absence of the fast-track procedure, would have to be made pursuant to the modification procedure of § 72.301; (2) for a change in a Phase I Extension, repowering extension, NO_x extension, NO_x averaging, or NO_x alternative emissions plan; or (3) for a change in an existing compliance option that results in a previously unaffected unit becoming affected under the Acid Rain program or an affected unit becoming unaffected. As is noted above, these types of changes are fundamental to the Acid Rain program and would normally be subject to the permit modification process. The time and resources involved in the permit modification process set forth in 40 CFR part 70 would, however, take away much of the source flexibility which the Acid Rain program was designed to ensure. Congress intended the Acid Rain program to promote least-cost planning through optional methods of compliance and an active allowance market. Requiring the affected source to go through a time- and resource-intensive process each time it wished to change its method of compliance would restrict much of the flexibility of the Acid Rain program. Sources should be able to revise their methods of compliance where the method originally chosen does not turn out to be costeffective.

Balanced against this interest is the need to provide an opportunity for public involvement to ensure that the source is held accountable for the requirements in its permit. The Agency is, therefore, proposing a fast-track modification procedure to avoid the excessive delays associated with the permit modification procedure proposed in 40 CFR part 70, while providing appropriate review and where appropriate public involvement. The proposal includes two options for the fast-track modification procedure. The Agency requests comment on both.

In most cases a prudent source, uncertain of the most cost-effective method of compliance, will seek conditional approval of several compliance options in its permit application and compliance plan. The Agency encourages sources to do this. In this way, when the source notifies EPA of the compliance option it wishes to use, or that it wishes to switch methods, the permit could be revised through the administrative amendment procedure discussed below. (See, also § 70.7(e).) The Agency believes this approach is appropriate because the compliance option will have undergone public notice and comment during the permit issuance procedure.

Sources may not, however, always be able to predict all possible methods of compliance that they might need during the permit issuance process. A source may wish to change the method of compliance for a unit in the middle of the permit term.

Three approaches to fast-track modifications are offered. Under the

[21] The concept of "modification" as used in an Acid Rain Program context is distinct from the use of the term in an NSR or NSPS context under parts C or D or section 111 in title I of the Act. The Agency's proposed "WEPCO decision" (56 FR 27630, June 14, 1991), therefore, does not affect today's proposal. The revision of the modification definition for purposes of "WEPCO" concerns physical or operational changes to the facility, in particular, pollution control projects which could affect ambient air quality. Certain changes (pollution control projects) will be exempt from NSPS and NSR so long as they are "not less environmentally beneficial". A change in an Acid Rain compliance option may or may not involve a pollution control project. However, no such change would alter ambient program requirements applicable to the source.

first approach, the applicant would submit the proposed revision to EPA. EPA would then have 30 days to approve or disapprove it. If EPA proposed to approve the revision, actual notice would be sent to interested persons, i.e., all persons who (1) commented on the proposed permit, or (2) requested to be informed of any subsequent permit actions proposed to be taken concerning the source. (The second category of interested persons could get their names on a mailing list for notice of any subsequent permit actions, whether or not they had comments on the initial proposed permit.) Interested persons would have 15 days in which to raise substantive objections to the proposed fast-track modification. If no substantive objections were received, the modification would take effect. If substantive objections were received, the proposal would have to go through the permit modification procedure, including general public notice, of 40 CFR part 70. Objections would be evaluated by the Agency, using the criteria in § 72.77, to determine whether they were substantive.

Under the second approach to fast-track modifications, the permittee would give public notice of its proposed new compliance option through publication in a journal (or newspaper) of national and general circulation. The permittee would also give actual notice to each interested person, on or after the permittee submitted the proposed compliance option to the Administrator. The notice would specify that all comments be submitted to the Administrator. The public would have 30 days to send comments to the Administrator. The Administrator would approve or disapprove the fast-track modification within 30 days after the end of the comment period.

EPA believes that either of these approaches would prove to be more expeditious than the permit modification procedures of 40 CFR part 70. The first approach is more streamlined than the second, so long as no substantive objections are raised. The second approach would be quicker if the public were to raise objections. EPA is considering whether to: (1) Promulgate the permit modification procedure of 40 CFR part 70 only, (2) choose one of the options for fast-track modifications, or (3) promulgate both fast-track modification options into regulation and allow the permittee discretion to choose which option to use. The Agency requests comment on these approaches.

In addition, as was mentioned above, the Agency will be promulgating final title V rules during the pendency of this rulemaking. The Agency, thus, also requests comment on whether any of the types of changes that would be subject to any of the modifications procedures in today's proposal could be handled under any procedures for minor permit amendments that may be established in the final title V rule.

3. Administrative Permit Amendments

The Agency also proposes to adopt, for purposes of the Acid Rain program, the administrative amendment procedures set forth at 40 CFR part 70. Changes to a permit, such as corrections of typographical errors, changes in names, addresses, and phone numbers, a change which requires more frequent monitoring at a source, and in most cases a change in ownership or operational control at a source are included under the administrative amendments procedures of 40 CFR part 70. Today's proposal would add to that list: Changes such as the activation of a compliance option which was previously conditionally approved in the original permit application; and changes to the designated representative, so long as a new certificate of representation is submitted pursuant to subpart B. The administrative permit amendment procedure would also be used to incorporate or revise a reduced utilization plan that does not involve a compensating unit, so long as the plan meets all the requirements specified in the regulations at § 72.43, and changes to a substitution plan that does not result in a previously unaffected unit becoming affected.

The Agency also proposes that the administrative permit amendment procedure be used to terminate an Acid Rain compliance option as authorized by the regulations. This approach would, however, be subject to the limitations on terminating options applicable to Phase I Extensions and Repowering Extensions, as well as the limitations on de-designating substitution units in § 72.41, and on de-designating compensating units in § 72.43.

In addition, the administrative amendments procedures would apply to incorporate alternative monitoring systems approved under 40 CFR part 75 of today's proposal, and excess emissions offset plans pursuant to section 411 of the Act approved by the Administrator according to procedures specified in 40 CFR part 77 of today's proposal into a permit. The procedures for these two categories of actions by the Administrator include public comment. Further public comment would, therefore, be redundant.

EPA asks for comment on the scope of permit revisions appropriately made pursuant to the administrative amendments procedures.

4. Minor Permit Amendments

Under proposed 40 CFR part 70 a minor permit amendment procedure is also authorized, to cover any proposed revision to a permit that is not a modification under title I.[22] This procedure is primarily intended to provide sources with operating flexibility in their day-to-day operations. Because the Acid Rain program is an annual program which, by definition, provides ample flexibility with regard to variation in operating conditions throughout the year, EPA does not believe that this procedure would be necessary for most types of revisions that will be seen in Acid Rain program.

The changes that utilities might need to make rapidly generally would not involve any sort of notice or permit revision under the Acid Rain program. For example, operational changes such as fuel switching would not normally require any notice. The few types of changes that would need to be made rapidly and for which notice might be required are covered under the administrative or automatic permit amendment procedures (e.g., end-of-year allowance transactions amend the permit automatically upon recordation with EPA). The changes that would necessitate a permit revision with significant input from the permitting authority are, under the Acid Rain program, all long-term changes. Thus, EPA believes that a two-month delay for approval of a new compliance option would not hinder the ability of sources to operate in a cost-effective manner. For example, a source may determine in the middle of the permit term that it is more cost-effective to make emissions reductions at a Phase II unit and to bring the Phase II unit in to Phase I as a substitution unit. Since allowances will be allocated on an annual basis, the source may specify whether the new allowance allocation is to be calculated retrospectively for that calendar year, or applied to the following calendar year. Any delay on the part of EPA in processing the revision (under the fast-track modification procedure, for

[22] The source would be required to notify the permitting authority 7 calendar days before the change is to occur. The rule would require the change to comply with all applicable elements of the Act relevant to the source. Under this procedure, the permitting authority has 7 days to notify the source if the change is not acceptable as a minor amendment, and it is then treated as a modification

example) would, therefore, not affect the source's ability to comply with the Act.

The Agency, therefore, believes that the minor permit amendment process will not be needed in the Acid Rain program. Thus, EPA is proposing that no revisions to the Acid Rain portion of a permit would be processed under the minor permit amendment procedure. However, EPA requests comment on the need for a minor permit amendment provision and specifically requests comment on the types of changes that would best be covered through minor permit amendments.

5. Automatic Permit Amendments

Today's proposal also provides that allowance transactions to or from a unit's Allowance Tracking System compliance subaccount that are properly recorded with EPA would automatically amend the permit. Title IV of the Act specifies that allowance transactions be treated differently from most permit revisions. The proposal reflects this statutory requirement. Allowance transactions are incorporated into permits as automatic amendments upon recordation by the Administrator. A detailed discussion of allowance transaction recordation can be found in the 40 CFR part 73 preamble.

L. Compliance Certification

Compliance certifications are a fundamental element of the Acid Rain program's implementation strategy. The term "compliance certification" is defined in today's proposal as a report signed and verified by the designated representative of the source's or unit's compliance or non-compliance with applicable requirements. The statutory authority for this requirement can be found in section 114(a) of the Act (as amended by section 702 of Act Amendments of 1990), which requires that the Administrator promulgate enhanced monitoring and compliance certification regulations, and in section 504(c) in title V of the Act, which requires that compliance certification requirements be included in each source's operating permit.

The Agency believes that heavy reliance on compliance certifications in the Acid Rain program will greatly increase flexibility, reduce the burden on sources of demonstrating compliance while maintaining the Agency's ability to ensure program accountability. They will also provide a helpful vehicle for resolving misunderstandings concerning applicable requirements before there has been a violation. This feature which should greatly increase program certainty for sources.

The strategy of relying heavily on certifications evidences a dramatic departure from the methods traditionally used to determine compliance, i.e., on-site inspections and source-specific investigatory letters requiring the collection and submission of emissions data and operational reports. The Agency proposes that every Acid Rain program submittal be certified as to its truth and accuracy by the designated representative. As is discussed in Subpart B, only the designated representative can submit compliance certifications.

Compliance certifications are categorized in today's proposal according to frequency of submission, such as quarterly or annual. The proposal specifies the contents and submission dates for these certifications and reports. The submission deadlines are consistent with the Agency's proposal today at 40 CFR part 73, specifying an end of year allowance transfer deadline for sources to consolidate data and conform their allowance accounts, and the emissions data reporting requirements of 40 CFR part 75.

Some compliance certifications would be submitted on an irregular schedule to provide the Agency and the permitting authority with notice of an operational change pertinent to the Acid Rain program (e.g., shut-down of a unit for repowering). The proposal also requires the designated representative of an affected unit employing one or more Acid Rain compliance option to include in the annual, quarterly, and other reports, the compliance certifications specified in the sections of the regulation for the relevant compliance option. For example, certain statutory compliance deadlines are specified under the Phase I and repowering extension provisions. In addition, sources may specify implementation deadlines, for example, for putting into effect energy conservation measures under a reduced utilization plan or for phasing in allowance distributions under a substitution plan. This rule does not, however, contemplate the use of detailed schedules and increments not mandated by the statute or sought by the source.

One data requirement that the Agency believes is an essential program element during Phase I is heat input and generation information. This information is necessary to ensure compliance with the reduced utilization requirements of the program (addressed in today's preamble discussion of § 72.43 and subpart C), and to allow sources the flexibility to pursue their normal dispatching operations while ensuring that SO_2 emissions are accounted for in accordance with section 403(d)(1) and (2) of the Act. The annual compliance certification for each Phase I unit would provide that if the unit has reduced utilization below its baseline, the designated representative must make one or more of several demonstrations to account for the SO_2 emissions that would have resulted from load shifts. The annual compliance certification would also require the designated representative to certify whether any reductions in utilization caused the unit to be subject to the planning requirements for reduced utilization in § 72.43 of subpart D.

1. Need for Information

Some information proposed to be required in annual compliance certifications is information that the Agency could obtain from other sources. This proposal contemplates, however, that compliance certifications be self-contained documents to the extent feasible. First, this will facilitate more expeditious review of a source's compliance status. In addition, the Agency believes that requiring the designated representative to report this information and certify emissions totals will provide an added verification of the data, and minimize the opportunity for disputes concerning the compliance status for each unit. The Agency requests comment on the scope of the information required to be included in the annual compliance certification.

M. Phase I Extension Early Ranking Procedures

Subpart L would provide the procedures for early ranking of Phase I Extension plans submitted under § 72.42 of today's proposal. Subpart L addresses two concerns: (1) The statutory mandate in section 404(d)(3) of the Act that submissions for Phase I Extensions be considered by the Administrator "in order of receipt", and (2) the need of the regulated community to know as early as possible whether they will be eligible for Phase I Extension allowances. Because of the economic benefits a source would derive from a Phase I Extension, some estimates indicate that the Phase I Extension allowance reserve of up to 3.5 million tons, mandated by section 404(a)(2) of the Act, may be oversubscribed. Many sources can, therefore, be expected to apply for Phase I Extension allowances in a short period of time, making it difficult to determine the "order of receipt" of a proposed Phase I Extension plan

submitted under § 72.42 by relying exclusively on postal delivery services.

The Agency is, thus, proposing an Early Ranking procedure for determining the order in which to act on Phase I Extension applications. The Agency proposes to use a voice-mail telephone queuing procedure followed by a written Phase I Extension Early Ranking application submission mailed not later than midnight of the same business day of the phone queue. The "order of receipt" established by the Early Ranking procedure would be conditional. In particular, it would be conditioned on timely submission by the designated representative for each applicant, in accordance with the procedures proposed in subpart C and § 72.42 of subpart D of today's proposal, of a complete and approvable permit application and proposed compliance plan by the Phase I permit application deadline of February 15, 1993 specified in section 408 of the Act.

1. Industry's Interest in an Accelerated Procedure

Information available to EPA indicates that it takes three years to design, construct, and install qualifying Phase I Extension control technology (i.e., 90% controls). The Agency believes that the Early Ranking procedure proposed today is necessary to provide sources considering installing such controls with a reasonable idea of whether they will be eligible for Phase I Extension allowances, and to allow utilities enough time to install the qualifying Phase I technology before January 1, 1997. (See preamble discussion of § 72.42 of subpart D, of today's proposal for a more detailed discussion of section 404(d) of the Act.)

2. Overview

Subpart L presents a voice-mail phone queuing procedure which sources seeking a Phase I Extension may use for obtaining an early ranking.[23] Subpart L also describes procedures for EPA action on Early Ranking applications. Currently available voice-mail systems can receive hundreds of calls within a short period of time, and rank them in order of incoming calls by milliseconds. The Agency proposes this approach because it is consistent with the statutory language of "order of receipt", and it affords an expeditious minimally burdensome way for giving applicants critical information regarding their eligibility for extension allowances at an early stage in the program.

As described in § 72.500, subpart L applies only during Phase I, and only to existing affected units for which a Phase I Extension is sought pursuant to § 72.42 of today's proposal. Consistent with other provisions of part 72, the designated representative(s) for the unit(s) in a proposed Phase I Extension plan would be the sole person(s) with authority to participate in the Early Ranking procedure under this subpart.

Under today's proposal, the designated representative for each affected unit that would be governed by the § 72.42 Phase I Extension plan would submit a certificate of representation. EPA proposes to issue a secure designated representative identification number to each designated representative within 30 days of receipt of a certificate of representation. (See, subpart B of today's proposal). These identification numbers are required to participate in the Early Ranking phone queuing procedure. The notice would include instructions for the designated representative to follow in order to participate in the phone queuing procedure. These would include procedures for registering a secure application ID# with EPA, for obtaining a secured phone number to call on the date of the phone queuing, the date and time of the phone queuing, instructions on how to enter information into the voice-mail system, and instructions and forms for the follow-up mailing.

Section 72.502 describes the Administrator's action on Early Ranking applications. Following the ranking, allowances would be conditionally awarded by the Administrator based on the order of each Early Ranking application as established by the phone queuing procedure, until all ranking applications were acted on or until the reserve appeared to be oversubscribed.

Because EPA recognizes the need for applicants to know their conditional ranking as soon as possible, subpart L proposes that EPA would notify applicants within 30 days after the conditional ranking is established through the phone queuing procedure. Allowance awards would be calculated based on the formula described in § 72.42.

The allowance awards would be conditional in several respects. First, they would be subject to an applicant's meeting the full requirements for timely submitting a complete permit application and Phase I Extension plan that are set forth in subpart D, § 72.42 and subpart C of today's proposal. The Administrator's action on Early Ranking applications would also be conditional subject to subsequent corrections to the information contained in the ranking application and to the results of challenges to the rule, if any are brought. Moreover, if subpart L is promulgated in final in advance of the rest of the core rules (parts 72, 73 and 75), the Administrator's action on Early Ranking applications would be subject to the designated representative modifying the application, as necessary, to conform to the part 72 rule as finally promulgated. One provision which would be promulgated at part 73 after the Early Ranking procedure is implemented, and which could significantly affect the allowance awards for each Phase I Extension plan, is the procedure for annualizing Federally enforceable allowable emissions limitations.

The ranking provided for in subpart L would, therefore, not constitute either an approval of a proposed Phase I Extension plan or an award of Phase I Extension allowances. Thus, the ranking provided for by subpart L would be presumptive, and conditional on the Administrator's review of, and action on, a complete Phase I Extension plan and approvable and timely permit application pursuant to subpart C and § 72.42. Likewise, Phase I Extension allowances would be awarded pursuant to the ranking procedure on a conditional basis only. The awards would be subject to the timely submission of the permit application and compliance plan, and to yearly demonstrations that the qualifying Phase I control technology for the control unit and the source has achieved 90% removal of sulfur dioxide (See, § 72.42). Actual approval of Phase I Extension plans and awards of Phase I Extension allowances would be made pursuant to the provisions of § 72.42. The conditional ranking would, however, give applicants greater certainty regarding the approximate distribution of the Phase I Extension allowance reserve, assuming all subsequently required submissions and steps are achieved. Any allowances returned to the reserve by the withdrawal of an application or by the failure of an applicant to meet all of the conditions of this subpart and § 72.42 of the rule would be conditionally awarded to the next application in the ranking order.

3. Other Approaches Considered for Determining "Order of Receipt"

a. *Modified phone queue approach.* Under another approach the Agency is considering the designated

[23] Sources that did not wish to participate in the Early Ranking procedure could wait until submitting their permit application, as provided in Subpart C of today's proposal, to submit a proposed Phase I Extension plan. The proposed plan would, however, have to be disapproved if the extension allowance reserve were oversubscribed.

representative would submit an Early Ranking application to EPA by certified mail when he or she submits the certificate of representation. EPA would begin accepting applications 15 days after the day the rule is promulgated in final in the **Federal Register**. Once an Early Ranking application was received, EPA would notify the applicant within 30 days whether the application was complete. An application would not be deemed to have been complete or received unless and until the certificate of representation required by subpart B was received by the Administrator.

All complete Early Ranking applications received by EPA on a given day would be considered to have been received at the same time. For applications received on a particular day that did not result in the Phase I Extension allowance reserve being oversubscribed, the notification of receipt would specify a conditional award of allowances. If, however, the applications received on a given day resulted in an apparent oversubscription of the Phase I Extension allowance reserve, a phone queuing procedure would be used to determine the "order of receipt" for the tied applications.

Beginning on the day of apparent oversubscription, for each application received on a day when more than one application was received, the Administrator's notification of completeness would specify that a phone queuing procedure would be used to determine the application's "order of receipt" for the tied applications. The notification would indicate the date and time (not earlier than 30 days and not later than 60 days after the date of the apparent oversubscription) when the phone queuing procedure would be carried out. In addition, the Administrator would issue with the notice procedures for registering a secure application identifier number for use during the phone queuing procedure. The period between the day of oversubscription and the day on which the phone queuing for that day was scheduled to take place, would provide each applicant an opportunity to decide whether to withdraw the application and proceed with other compliance options. Applicants would be able to elect not to participate in the phone queuing.

b. *Lottery*. Another option considered by the Agency is a chance drawing or lottery approach. As with the modified phone queuing approach, under this approach, the designated representatives for all applications received on the same day beginning on the day of oversubscription would be notified of the tie, and each applicant would be informed of the procedures for registering a secure application identifier number. The designated representatives would, thereafter, have 30 days to decide whether to participate in a chance drawing. Designated representatives that did not notify EPA in writing within 30 days to proceed with the chance drawing would be deemed to have withdrawn their applications. The chance drawing, using the application identifier, would be used to randomly establish the individual ranking of each tied application for which an election to participate was made. The designated representatives for participating applicants could be "present" at the drawing at their option.

c. *Date stamp*. Under another approach, under consideration for determining the "order of receipt" of Phase I Extension Early Ranking applications, applications would have to be submitted by certified mail. These would be date/time stamped by EPA in the order they were received at the location of the date stamp machine. The EPA time clock would determine each application's "order of receipt".

d. *Stand-in-line*. The Agency considered and is rejecting a stand-in-line approach to determining "order of receipt". Under this approach, applicants would have to deliver Early Ranking applications in person, and the rule would specify a date and time for applicants to begin submitting their applications. This approach, however, presented major logistical problems for the applicants, who would be required to wait in line, and for the Agency.

e. *Pro rata*. Another approach that was proposed to EPA, but is rejected by the Agency, was a pro rata distribution of reserve allowances. As in the modified phone queue and lottery approaches, this option would have provided for a window of submission that was one day long, so that any application received during a given day would be considered to have been received at the same time. The pro rata approach is also similar to the modified phone queue and lottery approaches discussed above in that, beginning on the day the applications received oversubscribed the reserve, a 30-day cooling-off period would be observed during which any applicant could choose to withdraw their application. The pro rata approach differs from the modified phone queue and lottery approaches, however, in that after the 30–day cooling-off period, the Administrator would award any allowances remaining in the reserve on a pro rata basis to the remaining applicants.

In considering this option, the Agency recognized that distributing reserve allowances pro rata to more applicants, rather than giving the full amount requested to fewer applicants, might potentially encourage the installation of more control technology. However, the allocation scheme ultimately adopted by Congress in section 404(d)—including the requirement that applications be acted on and allowance awards made "in order of receipt"—is very specific in requiring a sequential distribution of allowances from the reserve, rather than a distribution of a share of allowances to all applicants. In addition, a pro rata distribution would be substantially more time consuming than the approach proposed today. Nor would today's proposal preclude side-bar pro rata agreements between applicants, should utilities wish to pursue such arrangements. EPA would have no involvement, however, with such agreements.

4. Early Rulemaking

EPA is considering accelerating final promulgation of portions of today's part 72 proposed rulemaking in order to implement the Early Ranking procedures as soon as possible. The portions of today's proposal which would be included in an accelerated final package include subpart L, subpart A (general provisions), subpart B (designated representative certification procedures), and § 72.42 of subpart D. In the event comment on those subparts is favorable, the Agency would be in a better position to move forward with an accelerated rulemaking and early implementation of the Early Ranking procedure. Significant adverse comment on these provisions would make an early rulemaking less feasible.

V. Sulfur Dioxide Allowance System Regulation

A. Allowance Rule Background and Summary

1. Applicability

Today's proposal contains a statement of applicability to inform the public as to who is subject to the requirements of part 73. First, part 73 applies to owners and operators of sources of sulfur dioxide that are affected sources pursuant to title IV and § 72.7. Such affected sources, including new sources and sources that "opt in" pursuant to section 410 of the Act and part 74, are required to hold allowances sufficient to offset their sulfur dioxide emissions. Most existing utility units

and some new utility units will be allocated allowances by EPA pursuant to part 73, subpart B, part 72, subpart D, and part 74. Most new sources will not be allocated allowances, but will be required to purchase allowances. This part also applies to independent power producers (IPPs) as defined in section 416 of the Act (except those exempted under section 405(g)(6) of the Act), and in 73.74 of the Auctions, Direct Sale and IPP Written Guarantee Proposed Regulations. IPPs with written guarantees have priority in the purchase of allowances from the EPA Direct Sale.

Subject to the opt-in regulations, which will be proposed at a later date, any small diesel refinery as described in section 410(h) of the Act will also be covered by regulations in this part.

Finally, this part applies to any person who purchases, holds, and trades allowances as allowed in section 403(b) of the Act. The term "person" is defined in section 302(e) of the Act and includes an individual, corporation, partnership, association, State, municipality, political subdivision of a State, and any agency, department, or instrumentality of the United States and any officer, agent, or employee thereof.

2. Function of Allowances in the Acid Rain Program

As discussed in sections II and III of this preamble, the fundamental compliance mechanism for the SO_2 reduction program is an innovative system of marketable allowances. Since allowances are the fundamental instruments of SO_2 compliance, the Act requires EPA to establish a system for tracking allowances. Accordingly, the Allowance Tracking System must be reliable, and it must be designed and must function in a way that does not impair the ability of affected units to use allowance transfers to maximize efficiency in their compliance strategies.

3. Statutory Authority for the Proposed Allowance System

Section 403 of the Act creates the primary authority for the regulations proposed today. Excepting certain provisions in effect only through the year 2009, section 403(a) of the Act mandates that EPA allocate allowances for each affected unit in an amount equal to its statutory SO_2 emissions limitation requirement (expressed in tons), provided that no more than 8.95 million allowances are allocated annually after January 1, 2000.

Section 403(b) of the Act authorizes the transfer of allowances between and among units through the "designated representative" for the owners and operators of each unit, and between and among any other person holding allowances. Section 403(b) also requires EPA to promulgate regulations to "establish the allowance system prescribed under this section, including, but not limited to, requirements for the allocation, transfer, and use of allowances under this title." Pursuant to section 403(b), the regulations are to "prohibit the use of any allowance prior to the calendar year for which the allowance was allocated," while providing for "unused allowances to be carried forward and added to allowances allocated in subsequent years." Section 403(b) further requires "written certification of * * * transfer(s), signed by a responsible official of each party to the transfer * * *." Finally, paragraph (b) of the section states that "recorded pre-allocation transfers shall be deducted by the Administrator from the number of allowances which would otherwise be allocated to the transferor and added to those allowances allocated to the transferee." In addition, section 403(d) of the Act requires EPA to promulgate "a system for issuing, recording, and tracking allowances, which shall specify all necessary procedures and requirements for an orderly and competitive functioning of the allowance system."

At the same time, section 403(f) of the Act provides, in part, as follows:

"Nothing in this section shall be construed as requiring a change of any kind in any State law regulating electric utility rates and charges or affecting any State law regarding such State regulation or as limiting regulation (including any prudency review) under such a State law. Nothing in this section shall be construed as modifying the Federal Power Act or as affecting the authority of the Federal Energy Regulatory Commission under that Act. Nothing in this title shall be construed to interfere with or impair any program for competitive bidding for power supply in a State in which such program is established."

Section 408(i) of the Act requires a designated representative of the owners and operators of each affected unit to "file[] a certificate of representation with regard to matters under this Title, including the holding and distribution of allowances and the proceeds of transactions involving allowances." In the case of multiple owners, such certificate must address the holding and distribution of allowances and the proceeds of transactions involving allowances.

Finally, when a unit's SO_2 emissions exceed the number of allowances held for the unit, section 411(b) of the Act, in addition to imposing a $2,000 penalty for each ton (or fraction of a ton) of exceedance, requires EPA to "deduct allowances equal to the excess tonnage from those allocated for the source for the calendar year, or succeeding years during which offsets are required, following the year in which the excess emissions occurred."

4. Summary of Today's Proposed Rule

a. *Regulatory approach to the allowance system.* The design of the allowance trading and tracking system proposed today reflects the implicit roles Congress devised for the Agency, other regulatory agencies, and the market participants.

EPA views its role as filling three critical needs of the allowance trading market: (i) Neutral, low-cost rules of exchange; (ii) basic tracking information on allowances; and (iii) certainty in the identification of a person's authority to transfer allowances. EPA therefore approached the trading rules with the view that the system should be simple to understand and should impose minimal burdens on the participants. Under today's proposal EPA would provide the authoritative record of allowance account holdings and transfers, in order to fulfill its implied statutory mandate to assure certainty for the allowance market and its express mandate to ensure compliance with SO_2 emissions requirements. These roles are clearly laid out in section 403 of the Act and are implicit in Congress' direction that EPA establish an orderly and well-functioning market.

Similarly, today's proposal reflects the Act's express limitation on intrusions by EPA's regulations in areas of economic regulation of the electric utility industry that are already carried out by the Federal Energy Regulatory Commission (FERC) and State rate regulators (Public Utility Commissions, or "PUCs"). Such regulatory authorities will play a useful role in reviewing long-range plans of utilities as they comply with the requirements of the Acid Rain program.

The market participants themselves, which include both affected units and others, are the only parties who can "make the market work" by providing the various private commercial arrangements markets need to function efficiently. Indeed, in previous emission trading programs, the private market has created all necessary contractual and informational functions for the orderly operation of the markets. In view of this record and the ultimate exclusive role of private actors in determining the level of activity and efficiency of the market, it is EPA's belief that the EPA allowance system must provide flexibility to participants and be as unconstrained by

regulatory authority as is reasonable while meeting the stated environmental protection objectives of the Act. Therefore, in designing the proposed regulations for part 73, EPA eschewed any option that would cast the Agency in new purportedly "market-making" roles beyond those expressly prescribed by the Act.

b. *Overview of proposed rule.* As proposed here in part 73, pursuant to section 403(b) and section 403(d) of the Act, EPA will establish a system of allowance accounts for each affected unit and for any other person likely to hold allowances. Allowances initially allocated by EPA for each affected unit pursuant to sections 403(a), 404, 405, 406, 408, 409 and 410 of the Act and proposed parts 72, 73 and 74 will be held in these accounts. Transfers of allowances recorded with EPA will be effected by deducting allowances from the transferor's account and adding them to the transferee's account. To determine whether or not a unit has met its annual emissions control requirements, EPA proposes to deduct, at the end of each year from each unit's account allowances usable in that year in an amount equal to the unit tons of SO_2 emissions for the year, as recorded and reported pursuant to the emissions monitoring regulations proposed today at part 75 and part 72, subpart K. If a unit's allowances exceed its emissions of SO_2 for the year, allowances remaining in the account after each year's deduction will be carried forward and banked in the unit's account for the following year. If the unit's total emissions of SO_2 for the year exceed the number of allowances usable in the year held in the unit's account, then EPA proposes to deduct, at the end of each year from each unit's account, allowances usable in that year for the following year in an amount equal to the unit's excess emissions, pursuant to an excess emissions offset plan submitted for the unit under part 77.

Part 73 of the proposed Acid Rain rules sets forth the procedures for establishing accounts, and the procedures applicable to EPA and account holders in operating the account system.

c. *Design of the tracking system.* For an affected unit, each allowance account would include a "compliance subaccount" (and for accounts held by others, a "current year subaccount"), for allowances that may be used for compliance purposes in that calendar year, and a subaccount for each future calendar year. For example, in Phase I each unit would have a separate subaccount for 1995, 1996, 1997, 1998, and 1999. The latter subaccounts will reflect allowances that may be used for compliance in each subsequent specified year. Each compliance and future subaccount initially would reflect the number of allowances that the Act authorizes EPA to allocate for each year for the unit. Thereafter, each subaccount's allowances would be credited or debited to reflect any allowance transfers. EPA proposes to assign a unique identification number for each allowance, which will reflect the calendar year for which the allowance may first be used for purposes of compliance ("the compliance use date").

EPA proposes to provide for the automatic banking of allowances by retaining in the compliance subaccount any allowances remaining in the subaccount that are not deducted to meet the unit's emissions limitation requirements.

The proposed rule requires EPA to establish an Allowance Tracking System account for every existing affected unit, even if the unit is affected only in Phase II, by no later than January 30, 1993. This proposed action permits EPA to record in the accounting system any allowances Phase II units may acquire, through the allowance auction or from a private seller, during Phase I (*i.e.*, 1995–1999) and allows the Phase II units to trade their Phase II allowances immediately. In addition, EPA would establish accounts for new units, and for SO_2 sources that elect to participate or "opt in" to the allowance system, by becoming affected units for purposes of title IV (under part 74 and section 410 of the Act). Finally, any person may apply to EPA to establish a non-unit account for purposes of holding allowances, after the effective date of the part.

All matters pertaining to the account would be carried out by a person designated and certified as the authorized account representative for the account. In the case of unit accounts, the authorized account representative would be the designated representative for the unit, as established pursuant to the Acid Rain Permits regulations proposed today at part 72, subpart B.

As noted above, EPA proposes to determine a unit's compliance by deducting from the unit's compliance subaccount allowances equal in number to the SO_2 emissions tonnage reported for the unit pursuant to part 75 and part 72, subpart K for each year. EPA proposes today to establish as an "allowance transfer deadline," January 30 of the calendar year following the year for which compliance is being established, as the last day on which allowance transfers may be submitted to EPA for recordation in a compliance subaccount for use in meeting a unit's SO_2 emissions limitation requirements for the year.

After the allowance transfer deadline, if the unit's SO_2 emissions in tons exceed the number of allowances recorded in the unit's compliance subaccount, EPA proposes to "freeze," for purposes of subsequent transfers from the unit's account, allowances in the unit's compliance subaccount for the next year (i.e. the year following the calendar year in which the excess occurred), in an amount equal to the unit's excess emissions tonnage. The "freeze" would be lifted after EPA deducted allowances from the unit's compliance subaccount for purposes of offsetting the excess emissions, pursuant to the unit's approved excess emissions offset plan submitted pursuant to section 411 of the Act and part 77.

EPA will make available for public review the information, in summary form, contained in each allowance account.

d. *Annual timeline for subaccounts.* The compliance requirements of the Acid Rain Program are on a calendar year basis, under the proposed rules today. However January 30 of each year (the "allowance transfer deadline") will be the last day for submitting requests to transfer allowances to compliance subaccounts for purposes of meeting sulfur dioxide emissions requirements for the preceding calendar year. Following that date, EPA will record all requests to transfer allowances submitted by the allowance transfer deadline and will then deduct allowances from the compliance subaccount, equal in amount to the unit's SO_2 emissions tonnage for the year, reported pursuant to part 75 and part 72, subpart K in order to determine compliance for what, at that point, will be the preceding calendar year. Any allowances remaining in the compliance subaccount after the deductions will remain in the subaccount for the following calendar year and remain there until transferred, or deducted for compliance in a subsequent year. Once deductions have occurred, EPA will also replenish the compliance subaccount by adding to it, allowances in the future subaccount for what is now the current calendar year. Following this step, EPA will begin recording for the compliance subaccount transfers of allowances whose compliance use date is what, at that point, will be the current calendar year or earlier.

e. *Recordation of Transfers.* In the proposed rule, the exchange of allowances between account holders is made by submitting to EPA a request to record the transfer of allowances from one account to another. Until allowance transfers are recorded by EPA in a unit's account, they will not be available for meeting the unit's SO_2 emissions requirements. This is true regardless of what any commercial contractual obligation between two units to transfer allowances may be. Submissions to EPA of requests to record transfers may specify the identification numbers of the allowances to be transferred. As required by the Act, the proposed rule prohibits the transfer of an allowance usable in a specified calendar year to an allowance subaccount for an earlier year. In addition, EPA proposes not to record the transfer of any allowance if the allowance as specifically identified by its serial number in the transfer request does not appear in the transferor's account. Apart from this exception, EPA will record any transfer of an allowance from a unit's compliance subaccount without regard to the SO_2 emissions reported for the unit as of the date of the transfer. However, each transfer submitted for recordation that involves a unit account will be required to include an acknowledgement by the authorized account representative that EPA's recordation of the transfer shall not affect the unit's continuing legal obligation to comply with its requirements to hold allowances usable in that year in an amount equal to, or greater than, the unit's SO_2 emissions tonnage for the year.

f. *Timeline of allowance system activities.* Following the final promulgation of this rule and of each unit's Phase II allowance allocations, EPA will establish an Allowance Tracking System account for each existing affected unit, including those that will not become affected until the year 2000. Each account will include a subaccount for each year, beginning in 1995, until at least 2025. The owners and operators of each unit may select a designated representative for the unit and at any time after promulgation, the designated representative may submit a certificate of representation in accordance with part 72, subpart B. The designated representative for a unit shall be the authorized account representative for the unit's account. As soon as a certificate of representation is submitted, EPA will record any allowance transfer submitted by the designated representative, provided that the transfer meets the requirements of the allowance transfer regulations. In addition, any person may open a non-unit Allowance Tracking System account at any time after EPA establishes accounts for existing affected units. Draft forms are published today as part of the proposed rule. EPA may choose not to publish forms in the rule at promulgation.

By no later than December 31, 1991, EPA is required under section 403(a) of the Act to propose a list stating the number of allowances to be allocated by EPA to each Phase II affected unit, apart from any allocations under any compliance option in part 72, subpart D. By no later than the end of 1992, EPA must promulgate a final list of allocations. The final list for Phase II allocations is subject to mandatory revision by EPA in 1998, in order for EPA to offset the allowances allocated for units with approved repowering compliance plans pursuant to section 409 of the Act.

B. Allowance Tracking System

1. Function of Accounts

As proposed, the Allowance Tracking System (ATS) accounts will be the official records for allowance allocations, holdings and transfers, and will be used to track each unit's compliance. Initial allowance allocations, using calculations to be promulgated in part 73, subpart B (at a later date) and reflecting each unit's statutory SO_2 emissions limit, as well as allocations pursuant to part 72, subpart D, provide the starting point for tracking allowances. All allowance transfers to and from the accounts will be recorded to track the unit-by-unit holding of allowances as they are transferred. For the purposes of determining compliance EPA proposes to deduct allowances from each unit's compliance subaccount in an amount equal to its annual SO_2 emissions in tons as reported pursuant to part 75 and part 72, subpart K.

2. Subaccounts

EPA proposes that each unit account include a compliance subaccount. The compliance subaccount will hold all allowances that may be used for purposes of meeting the unit's SO_2 emissions limitation requirements in the current year. Each account will also include a future year subaccount for each of the 30 years following the current year, which would reflect allowances usable for compliance purposes in each specified future year.

The proposed system, which creates a record both of current and future allowance holdings, is compatible with the decision-making and planning functions of utilities. Long-term planning is characteristic of utility business practices in meeting their electric generation obligations and is nearly indispensable in meeting emissions limitations. For the latter purpose many utilities will rely on the installation of control technology, which must be planned on a long-term basis, or on switching to lower SO_2-emitting fuels, which also requires long-term contractual commitments and, in some cases, equipment modifications. In general, 30 years is considered to be an average operating life of an electric utility unit, not including any repowering or life extension. Thus, EPA believes that future year subaccounts spanning 30 years would facilitate long-term planning for meeting emission requirements within the standard operating life of a unit. Furthermore, transfers involving allowances to be allocated in years after the 30 year period tracked in the ATS may be submitted for recordation by EPA at any time. The transaction would be noted in the transferring accounts and then would appear in the applicable future year subaccounts at the time they were added to the ATS.

a. *Compliance and future year subaccounts.* Separating allowances between those usable in the current year and those usable in future years is intended to implement the Act's prohibition against the use of any allowance prior to the calendar year for which the allowance was allocated. Because only allowances recorded in a unit's compliance subaccount can be used to offset a unit's emissions, the proposed allocation and account structure would preclude the use of future year allowances in offsetting current year emissions.

EPA is proposing that the future year subaccounts cover at least the first 30 years following the current year, beginning with 1995, and continue to cover a 30-year period following each successive year. This means that at any point in time, any account holder would be able to view a unit's allowance balances for each year for each of the next thirty years. Any transfer of an allowance for any of the years in the 30-year period can be recorded in the Allowance Tracking System.

b. *Allocations in future year subaccounts.* As proposed today, future year subaccounts will reflect allowances allocated for each unit for each future year in the proposed 30-year timespan for subaccounts. At first, these allocations will reflect each unit's statutory emissions limitation requirements pursuant to the Act's

section 403, section 404 Table A (as modified by section 416) for Phase I, and section 405 for Phase II, as well as certain additional allocations prescribed in the Act. Subpart B of part 73 and appendices A and B of part 72 will provide these allocations.

Title IV of the Act and proposed part 72 also provide for alternative methods of compliance. In Phase I certain units may obtain additional allowances for up to two years. Pursuant to the Act and proposed § 72.42, EPA will allocate additional allowances for those units that qualify. In addition, Phase I units may meet their SO_2 emissions limitation requirements by substituting emissions reductions made at other units, not listed on Table A of section 404 of the Act. Here, too, EPA is required by the Act and proposed § 72.41 to allocate additional allowances pursuant to substitution plans. Allowances are also used to implement Phase I reduced utilization plans when emissions reductions at Phase I units are achieved by shifting electrical generation to units not otherwise affected in Phase I.

The Act also permits additional allocations for Phase II units that use qualifying repowering technologies, pursuant to section 409 of the Act and proposed § 72.44. In addition, the Act (and proposed subpart F) authorizes EPA to allocate allowances to utilities that adopt certain conservation and renewable energy measures or technologies. Section 410 of the Act authorizes EPA to allocate allowances to sources who "opt in" to the allowance program, and certain small diesel refiners. Finally, subpart E, proposed on May 23, 1991, will provide for the allocation of a reserve of allowances for those who purchase them at public auction or through a direct sale.

Today's proposal provides that future year subaccounts will reflect all such additional allowance allocations as they are made for affected units pursuant to part 72 compliance plans, or to other applications required by proposed part 73. Again, allowance holdings are integral to utilities' compliance strategies. Since these are usually formulated on a long-term basis, EPA believes that it is essential that the tracking system reflect all allowance allocations for each year, as soon as they are made, in order to facilitate utilities' mapping of their long-term strategies.

c. *Transfers in future year subaccounts.* EPA proposes to implement the statutory mandate to record "pre-allocation transfers" by following the method, prescribed in section 403(b), of the Act of "deduct[ing] * * * from the number of allowances which would otherwise be allocated to the transferror, and add[ing them] to those allowances allocated to the transferee." This will be done simply by adding and deducting allowances in the relevant future year subaccount.

This process enables the Allowance Tracking System to reflect a unit's allowance holdings for any future year as soon as a transfer is recorded. As a result, at any given point in time, there will be up-to-date and reliable information about units' current and future year allowance holdings. Again, this appears to EPA to be indispensable to providing the information and certainty utility managers and others require in planning compliance and incorporating allowance transfers in their planning.

Specifically, EPA expects utilities to execute long-term "forward" contracts providing for the transfer of allowances for a period of years well beyond the time at which such contracts are negotiated. Not only would such contracts be indispensable to conforming compliance plans, but they would assure sellers of reliable revenues and buyers of a supply of allowances at a known price, thus providing both parties with a method for managing and sharing risks associated with fluctuations in allowance price and availability.

Apart from the method for recording the transfer of an allowance with a compliance use date more than 30 years beyond the current year, which is discussed below, EPA considered, but proposes to reject, an alternative scheme of recording transfers which would have recorded the submission of future year allowance transfers but delayed the recordation or effectuation of the transfers until (1) the subject allowances were to be recorded in the compliance subaccount at the beginning of the current year, and (2) any allowance deductions were made from the transferor unit's account, pursuant to any excess emissions offset plans under section 411 of the Act and part 77. The rationale for this approach is that it would come closer to guaranteeing that there would also be a sufficient number of allowances in a unit's future year subaccount to offset a unit's excess emissions, as required by section 411. At the very least this alternative scheme would preclude the possibility that allowances required to be deducted to offset excess emissions would have been transferred to another unit, leaving the transferor account without sufficient allowances to meet the offset deduction requirement.

EPA proposes to reject this alternative for several reasons. First, the proposed approach makes it easier for utilities to use the Allowance Tracking System as a source of reliable information for purposes of planning compliance and exploiting the efficiency opportunities of allowance transfers. Under the proposed approach, each Allowance Tracking System unit account will display each unit's allowance holdings for each year, current and future, and each year's holdings will reflect recorded allowance transfers. The alternative, in contrast, would require those who needed information concerning units' future year holdings—such as would-be purchasers or sellers of allowances, including other utilities seeking to establish collective compliance strategies—to calculate their own and other units' future allowance holdings based on listed transfers.

Second, under the rejected approach, those transfers would be subject to uncertainty, since they would not be effectuated until after allowances had been deducted for purposes of offsetting excess emissions pursuant to section 411 of the Act. As a result, allowance transfers that had been agreed upon could be negated, at least in part, if, pursuant to section 411, EPA deducted allowances from the transferor's subaccount prior to effectuating a transfer from the subaccount. EPA acknowledges that private parties engaging in allowance transactions could provide, by contract, to indemnify the transferee in the event that a pre-transfer deduction of allowances for offset purposes defeated the transfer in whole or in part. EPA concluded, however, that both the mandate in section 403(b) of the Act to record pre-allocation transfers as well as the underlying policy of title IV militate against a recordation rule that would force the allowance market to absorb the transaction costs associated with contractual indemnification. While section 411 of the Act imposes severe penalties on those units whose SO_2 emissions exceed the number of allowances they hold, the compliance planning provisions of section 408(b) of the Act suggest a policy of affording all units maximum flexibility in meeting their emissions limitation requirements, at least until such time as they violate those requirements. Because of the uncertainty it would cause and the transaction costs associated with overcoming that uncertainty, delaying the recordation of transfers involving future year allowances would have the effect of penalizing all units, not just those violating their emissions obligations, and could interfere with utilities' ability to exploit the full cost-

saving potential of the allowance market.

At the same time, EPA does not believe that the rejected approach concerning future year allowance transfers would significantly enhance the compliance scheme embodied in section 411 of the Act. There is little likelihood, EPA believes, that the proposed rule would foster frequent situations in which units with excess emissions had insufficient allowances, as a result of previous transfers, to permit EPA to make deductions pursuant to section 411 of the Act and part 77.

3. Non-Unit Accounts

EPA is also proposing to establish accounts for persons other than affected units because section 403(b) of the Act expressly authorizes "any person," in addition to the designated representatives for affected units, to hold and transfer allowances. These non-unit accounts would provide the vehicle through which persons, such as brokers or utility power pools, seeking to aggregate allowances allocated for individual units could hold and transfer allowances. Non-unit accounts would include a current year subaccount and subaccounts for each of the 30 future years following the current year, beginning with 1996.

EPA is proposing to establish a non-unit account following the receipt of a new account application. The application would be required to include a certification by the authorized account representative. This is intended to protect ownership interests in any allowances held in the account, through disclosure of information and verification that the owners have agreed to the authorized account representative.

Both the legislative history of section 403(b), of the Act and EPA analysis suggest that brokers, investors and other market-makers may play a crucial role in facilitating allowance transfers. (See S. Rep. No. 228, 101st Congress, 1st Sess., p. 320 (1989).) In addition, as suggested by section 403(d)(2) of the Act, groups of units may choose to pool some or all of the allowances allocated for each unit. A non-unit account, created by the owners of such units but separate from the individual unit accounts, may serve as the mechanism for pooling their allowances. Since these allowance brokering and pooling functions are intended to facilitate utilities' efforts to maximize the efficiency of their compliance strategies, the Allowance Tracking System accounts through which these functions may be carried out should be integrated with the account system established for affected units. Accordingly, EPA proposes establishing non-unit accounts that parallel unit accounts, with multiple future-year subaccounts.

4. Identification Numbers for Allowances

EPA is proposing that each allowance be identified by a unique number that would include digits identifying the allowance's compliance use date, i.e., the first year for which it could be used. Members of the public have suggested that such a unique number identifying each allowance would enable utilities to structure transfers in order to ensure favorable accounting for purposes of regulatory rate and tax treatment. At the same time, without this unique number and the accounting procedures it would facilitate, the proceeds of allowance transactions might be taxed or treated for ratebase purposes in a manner that would discourage transfers or otherwise create implicit disincentives for adopting innovative or cost-efficient compliance strategies.

EPA believes that the potential for favorable financial accounting and tax treatment that may be tapped by the use of unique numbers could enhance utilities' confidence in the allowance market as a source of cost savings. Increased activity in the market that might ensue from this heightened confidence, in turn, might lower overall compliance costs. These cost savings for affected units could more than offset any additional administrative burden or cost to EPA and the affected parties associated with adopting serial numbers. Furthermore, representatives of the Chicago Board of Trade, which recently announced its intentions to create an allowance exchange, have advised EPA that the development of any organized commercial exchange would be greatly assisted by EPA's serialization of allowances, enabling interested parties to verify and track individual allowances through the course of commercial transactions. The Chicago Board of Trade noted that serialization is always used for bonds, commodities, and other tradeable debentures.

At the very least, EPA believes that giving each allowance a unique number provides flexibility to allowance holders in determining compliance strategies. The ability to distinguish one allowance from another could enable allowance holders to maintain records of the different costs incurred in acquiring or generating excess allowances, such as through emissions reduction, energy conservation measures, or other compliance strategies. This could aid utilities in demonstrating the basis for offsetting the economic gains received from the sale or utilization of particular allowances. Finally, including digits reflecting the compliance use date of each allowance would facilitate the ability of the buyer to ensure that an allowance could be used in a particular year.

EPA acknowledges that it holds some reservations in making this proposal. In the absence of formal identification of allowances by EPA, allowance holders could readily establish their own allowance-numbering system for tax and internal record-keeping purposes. Inventory systems created by each utility could serve some of the same financial ends that would be advanced by means of the proposed identification of unique allowances by EPA. At the same time, identification by itself does not ensure the favorable accounting treatment utilities may be seeking. Even with allowance identification provided by EPA, utilities seeking to gain more favorable tax or ratebase treatment would still have to link specified allowances with particular costs or transactions or compliance strategies.

In addition, assigning a unique number for each allowance would increase administrative complexity for both EPA and users of the Allowance Tracking System. Some additional administrative burdens would be placed on the authorized account representatives. Unless they accepted the default provisions proposed today, utilities would have to identify by serial number those allowances to be transferred, those to be deducted from the compliance subaccount for compliance purposes each year, and those to be deducted from the compliance subaccount to offset excess emissions, if any. Including a unique number for each allowance increases the possibility of errors in transfer requests, even if automated recordation systems are developed. This would add to the amount of time each authorized account representative would have to spend reviewing an allowance transfer request before submitting it to EPA, and verifying the transfer information after recordation by EPA in the tracking system. For these reasons, EPA is seeking public comment on the advisability of any serialization method.

EPA considered and rejected three other options for identifying allowances. The first option was to identify allowances only by the year in which they are first usable for compliance purposes. This would mean that all allowances for the same year would essentially be identical for compliance

tracking purposes. This approach minimizes the administrative burdens for EPA and for the authorized account representatives. However, minimizing administrative burden would be of little relative benefit if uncertainty concerning accounting and tax treatment, in the absence of a detailed allowance identification scheme, inhibited allowance trading and resulted in unnecessarily high compliance costs. Because of the risk of inhibiting more efficient compliance strategies, this option was rejected.

The second option EPA considered and rejected was to identify allowances by the year in which they are first usable for compliance purposes and then to assign a number to each transfer. This transfer number would include the date of the transfer and the method under which the allowance was being acquired (e.g., auction, direct sale, reserve allocation, bilateral transfer, etc.) for all the allowances involved in the transfer. EPA considered this option because a similar approach is used by both the New York Stock Exchange (NYSE) and the National Association of Securities Dealers Automated Quotations (NASDAQ) in reporting stock trades to the National Stock Clearing Corporation (NSCC). However, the identification number reported to NSCC is only used for NSCC purposes, and not for the use of the purchaser or seller of the stock.

EPA believes that this method might be useful from an accounting standpoint by offering some advantages of flexibility to the allowance holder in establishing inventory methods to record the acquisition and disposition of allowances without impairing the fungibility of allowances. The lot identification number can be used for tax and accounting purposes, connecting the date and price with the quantity of allowances purchased in a single transaction.

On the other hand, by recording each trade, including the identity of the transferror and transferee, and the amount of the allowances transferred (and the year in which they are first usable for compliance), EPA would already be capturing this information. This approach does not appear to add any value to the option of identifying allowances by the year in which they are first usable for compliance. In addition, assigning a number to each transfer could lead to some confusion, because each time the same allowances were transferred they would be assigned a new number.

The third option EPA considered and rejected was to assign a number identifying the unit for which each allowance was initially allocated or the reserve from which each allowance was initially allocated, in addition to a number denoting the year it could first be used for compliance purposes. Such identification might enable utilities to establish different cost records for allowances allocated or purchased, because those allowances would be distinguishable by the different numbers denoting their originating unit and compliance use date. Supplemented by a record of the dates of allowance transfers in the ATS, this approach would enable utilities to identify with specificity those allowances which they wanted to include in particular transactions or with which they wanted to associate certain costs. Furthermore, it would be easier for EPA to administer and, with less detailed specification of allowances to be transferred required, would result in lower probability of error in transfer requests and recordation by EPA. All of these benefits, and others already discussed, however, can be achieved by today's proposal.

EPA invites comment on the assignment of a unique identifying number to each allowance and on the other options considered. Comments are specifically requested on the benefits, such as favorable tax or ratebase treatment, that may be realized relative to the administrative disadvantages and higher transaction costs, and the extent to which those benefits are available through the options discussed.

5. Authorized Account Representative

a. *Certification and function.* The proposed rule requires the appointment of an authorized account representative for each account. The authorized account representative will be the only person authorized to carry out activities, such as allowance transfers, involving direct contact with EPA concerning the Allowance Tracking System account.

In the case of an account for an affected unit, the authorized account representative must be the designated representative for the owners and operators of the unit, certified pursuant to section 408(i) of the Act and proposed part 72, Subpart B. section 408(i) of the Act virtually mandates that in the case of affected units, the designated representative conduct transactions involving allowances. Therefore, the designated representative must function as the person with the sole authority to engage in transactions and other activities concerning the Allowance Tracking System account.

For non-unit accounts, the authorized account representative shall be the person designated in the New Account/New Authorized Account Representative Form submitted to EPA for opening the account. No allowance transfers for non-unit accounts will be recorded until the authorized account representative has signed a certificate of representation on the New Account/New Authorized Account Representative Form and EPA has approved the new account. The proposed certificate of representation for the non-unit authorized account representative would include: (i) A list of all persons with an ownership interest in the allowances held in the non-unit account; (ii) a statement that the representative was selected by an agreement binding on all persons with an ownership interest in the allowances held in the non-unit account; (iii) a statement that the authorized account representative has all necessary authority to carry out the duties and responsibilities of the authorized account representative; and (iv) a statement that the authorized account representative will abide by the fiduciary responsibilities assigned pursuant to the agreement of representation. Where all ownership interest in the allowances rests with a single person, the certificate shall state that all allowances purchased by the person are deemed to be held for that person. EPA is proposing to allow the authorized account representative for a non-unit account (as with the designated representative) to designate one alternate authorized account representative in the event that the authorized account representative is absent or otherwise not available to perform actions or duties necessary at some point in time.

Authorized account representatives for non-unit accounts may be succeeded by any person who submits a New Account/New Authorized Account Representative Form and signs the certification of representation. The non-unit account authorized account representative will also be required to amend the list of persons with ownership interest whenever appropriate.

EPA is proposing these authorized account representative requirements for two basic reasons. First, EPA interprets section 408(i) of the Act to impose such requirements in the case of unit accounts. Second, EPA believes that these requirements are essential to the efficient and reliable operation of the Allowance Tracking System and, by extension, to the market for whose activities it is the official record.

Section 408(i) provides in part: "No permit shall be issued under this section

for a unit until the designated representative of the owners or operators has filed a certificate of representation with regard to matters under this title, including the holding and distribution of allowances and the proceeds of transactions involving allowances." Section 408(i) also requires the designated representative to file a certificate of representation concerning the holding and distribution of the unit's allowances between and among co-owners. To give effect to these provisions EPA believes that the designated representative must function as the person with sole authority to engage in transactions and other activities concerning the Allowance Tracking System account.

Under the proposed requirements, EPA will be receiving information and instructions concerning transfers from only one person (or an alternate if one is specified in the certificate of representation) for each account. That person will be certified as the person authorized by the owners and operators of each unit, in the case of unit accounts, or by the owners of the allowances, in the case of non-unit accounts, to take action with respect to the allowance account. In addition, the owners and operators will have entered into an agreement governing the use and distribution of the allowances in the account. Finally, the authorized account representative will be certifying, in each submission to EPA, including allowance transfer submissions, that he or she is acting with full authority.

The effect of these three certifications—certification of representation, certification of the fact of an agreement governing allowances and certification of authority to act—is to establish a basis for EPA's reliance on transfers submitted by authorized account representatives for recordation in Allowance Tracking System accounts. Under this proposed scheme, EPA will be able to record any transfer submitted for recordation by the authorized account representatives for the accounts involved. The full legal effect of each recordation will be final as soon as recordation is made, without requiring EPA or the market to resort to secondary or additional confirmation of a transfer. This, in turn, will enhance EPA's ability to make final recordation of transfers quickly after they are submitted. Speedy final recordation will serve the interests of the parties to the transfer. Moreover, to the extent that the Allowance Tracking System will also function as a central source of public information as to allowance holdings, quick final recordation will assist all participants in the market. As applied to authorized account representatives for non-unit accounts, none of these certifications is required by the Act. The Agency is seeking specific comment on whether these requirements are necessary and whether they might impose undue burdens.

b. *Objections.* The proposal specifies that objections concerning a certificate of representation, allowance transfer, or any other submission to EPA by the authorized account representative will have no effect on the recordation by EPA of an allowance transfer. That is, once an allowance transfer is recorded, the recordation will continue to have full effect, even if an objection is communicated to EPA subsequently. At the same time, EPA will continue to record transfers properly submitted and certified by an authorized account representative even after EPA becomes aware of an objection.

In addition, under today's proposal EPA will not adjudicate disputes between private parties concerning allowances or the actions of the authorized account representative. In part 72, EPA is proposing the same provisions for the designated representative, who will be the authorized account representative for unit accounts.

These provisions are proposed for several reasons. EPA interprets section 408(i) to require certain certifications and to authorize EPA to enforce such certifications. Clearly, EPA has authority under section 113 of the Act to pursue appropriate sanctions in the event that an authorized account representative falsely certifies that he or she has been authorized to undertake an action. Thus, upon a demonstration of the falsity of a certification, EPA would be in a position to pursue such sanctions. EPA believes that the threat of sanctions will greatly reduce the likelihood that authorized account representatives would submit false certifications or otherwise act against the rights of owners.

Similarly, owners injured by the actions of an authorized account representative taken in contravention of their ownership rights would be able to seek injunctive or monetary relief from the courts or to pursue other private dispute resolution procedures agreed to by the owners. Such relief would be available pursuant to the private commercial agreements and obligations between the owners and their representative, existence of which agreements must be certified pursuant to section 408(i) of the Act and the proposed regulations in part 72 and part 73. Aggrieved owners would also be able to replace the authorized account representative. For these reasons, EPA has concluded that its authority under the Act, remedies available under commercial law governing the obligations between and among owners and their agents, and the ability of owners to appoint a successor authorized account representative, affords EPA and owners ample protection and recourse against wrongdoing by authorized account representatives.

At the same time, EPA believes that it would undermine the competitive and orderly functioning of the allowance market if the pendency of an objection, or even a determination that a certification with respect to a particular transaction was false, defeated the recordation of past or prospective allowance transfers (apart from an express judicial order mandating the reversal of a recordation or a bar on future recordation). First, EPA believes that third parties must be able to rely on the full effectiveness of the recordation of an allowance transfer. A rule that subjected transfers to the possibility that they might be canceled even after recordation would introduce uncertainties. These would impair the efficiency of the market by either inhibiting activity or imposing additional transaction costs incurred in an effort to provide against such uncertainties. Second, if the mere filing of an objection forced EPA to suspend recordation of transfers to or from an account, unwarranted objections could introduce disorder in the market or force authorized account representatives to make unreasonable concessions simply to satisfy objections however unwarranted. At the same time, for owners with legitimate grievances, suspending transfer activity would not enhance protection for co-owners appreciably beyond that already provided by the deterrent effect of civil remedies for protecting private commercial rights.

Finally, EPA does not believe that section 408(i) extends EPA's authority to determine or enforce commercial obligations between and among owners. Even where the veracity of a certificate of representation depends on an interpretation of such obligations, EPA believes that it does not have the authority or competence, particularly in contrast to existing avenues for resolving commercial law disputes, to resolve such disputes. (See part 72, subpart B and preamble for further discussion of these issues.)

6. Account Contents

The proposed account contents in the Allowance Tracking System will provide the minimum information needed by the authorized account representatives and EPA to track compliance. First, EPA is proposing to list information about the authorized account representative, including name, address, phone number, and telefacsimile number. This information is necessary for compliance purposes, because EPA must know to whom and where to submit communications concerning accounts. Authorized account representative information will help other authorized account representatives to make contact with potential trading partners or check the accuracy of other account information. Absent such information, allowance trading activity potentially could be hindered. In addition, if EPA did not establish and disseminate an official record of all authorized account representatives, unscrupulous or incompetent persons could misrepresent themselves to the market as account holders.

Second, EPA is proposing to include a list of all allowance transfers to or from the account, identifying transferror and transferee accounts and the quantity and identification of allowances transferred. This transfer information is useful for both the users and EPA to know what has occurred in the market, to help authorized account representatives verify accounts, and to help trace account recordation mistakes.

Third, the serial number of all allowances is necessary in order to confirm the proper allocation of allowances to the compliance subaccount, and to determine the compliance status for each unit. As stated earlier, allowances may not be used prior to the year for which they are allocated. Usable allowances will, therefore, be recorded in a unit's compliance subaccount, and these can be used to offset a unit's emissions in any year. Since EPA proposes to use serial numbers that reflect each allowance's compliance use date, listing the serial number simply makes it easier for EPA to use the subaccount system for implementing the Act's prohibition against the use of future year allowances for current year compliance.

Fourth, recording allowances in the future year subaccounts is necessary to track all recorded transfers throughout the proposed 30-year timespan. Again, these subaccounts allow for the segregation of allowances between the current year and future years as well as between each future year.

Finally, for unit accounts, EPA is proposing to include reports of the total tonnage of emissions for the calendar year as reported to date pursuant to the rules in Part 75. EPA may choose to include other information in the Allowance Tracking System should such information prove useful to the users of the system, and solicits comment on what information this might be.

7. Compliance

a. *Allowance transfer deadline.* The Allowance Tracking System account will be used by EPA to determine compliance by a unit with its SO_2 emissions limitation requirements. Consistent with the requirements in § 403(b) of the Act, EPA is proposing that no allowance can be used for the purposes of compliance with a unit's annual emissions limitation requirements for SO_2 unless, as of the allowance transfer deadline, such allowance is recorded in, or properly submitted for recordation in, the compliance subaccount for the unit. EPA is proposing that the allowance transfer deadline be January 30 of the calendar year following the year for which a unit's compliance is being determined.

b. *Purpose of an extended allowance recordation period.* Including an allowance transfer period extending beyond the end of the calendar year appears to EPA to be consistent with the flexibility of the acid rain provisions. Although no such extended allowance recordation period is explicitly mentioned in the Act, and today's proposal does not alter the calendar year compliance requirements of the Act, the Statement of Managers included in the Conference Report for the Amendments states that "the conferees do not intend that any affected unit be subject to any penalty for 'exceeding' its allowances for a given year until that year has ended and all transfers of allowances * * * have been completed within a reasonable time period after the end of that year." (Conf. Rep. No. 952, 101st Cong., 2nd Sess., p. 343, 1990.) In addition, the added time to transfer allowances into a unit's account would not compromise the emissions reduction requirements of the acid rain program, because only those allowances useable for the calendar year during which the emissions occurred would be transferrable to the compliance subaccount for the year. Thus, as would be the case in the absence of an extended allowance transfer period, only those allowances allocated for use in the year for which each unit's compliance is being determined and those allowances banked from earlier years would be available to offset emissions at the unit in that year. The extended transfer period does not increase the aggregate balance of allowances available for use for purposes of compliance in any year.

The extended allowance transfer period is appropriate for several other reasons as well. The additional time after the end of a year for transferring allowances would allow affected units to avoid violations where allowances are otherwise readily available for purchase to offset emissions. The extended allowance transfer period would allow owners and operators of units to avoid violations resulting from unforeseen circumstances. In those instances where a unit must significantly increase its generation in the last few days of the calendar year, the extended allowance transfer period provides an opportunity to purchase allowances and avoid the penalty.

In addition, the extended transfer period would not dampen incentives for prudent behavior or amplify perverse incentives. Whether the allowance transfer deadline is December 31 or later, prudent owners will plan well enough in advance to avoid the need to purchase allowances during the potentially inflationary period just prior to the final date for effectuating transfers. Similarly, would-be sellers who may be hoarding allowances to exploit predeadline inflation are no less likely to do so in the face of an end-of-year transfer deadline as opposed to a later allowance transfer deadline.

c. *Power and allowance pools.* For power and allowance pools, the allowance transfer deadline would enable units to implement arrangements where allowances could be transferred after the designated representatives fully collected and assessed the final emissions data for the year on a system-wide or pool basis. At that point, since compliance is determined on a unit-by-unit basis rather than an aggregate basis, surplus allowances from certain units could be transferred during the extended allowance transfer period to any units in the pool that needed them.

Some members of the public, pointing to section 403(d)(2) of the Act, which refers to "pools," have suggested that EPA promulgate special provisions to accommodate utilities in power pools or those seeking to create allowance pools. For example, they argue, EPA should permit pool-wide compliance with respect to total annual SO_2 emissions and allowances held for all units in such pools. EPA does not, however, interpret section 403(d)(2) or section 408(b) of the Act, which governs compliance plans and permits, to require or authorize such

an approach. Furthermore, section 403(g) of the Act specifically requires unit-by-unit compliance, and section 411 of the Act imposes excess emissions penalties on the basis of unit compliance. This supports EPA's conclusion that compliance is to be based exclusively on unit-by-unit emissions and allowance holdings (with the exception of certain multi-unit compliance methods specifically provided for in the statute).

Even in the absence of special rules applicable to allowance pools, both the legislative history of title IV and the title's treatment of SO_2 emissions and allowances as completely fungible make it clear that allowance pools are expected to be created, and to operate, in the context of unit-by-unit compliance. The proposed January 30 allowance transfer deadline, together with utilities' capability, through continuous emissions monitoring, to estimate an individual unit's emissions during the year and to determine each unit's total annual emissions within hours of year-end, should provide power or allowance pools ample time to transfer allowances between and among units. The allowances could be held either in a nonunit account for the purposes of creating a pool or simply in unit accounts but subject to a pooling agreement. Allowances would be transferred between and among units (i.e., into the unit accounts) in amounts necessary to cover emissions from each unit. This approach, which relies simply on the mechanics of allowance transfers, appears to EPA to be more conducive to flexible pooling strategies than would an alternative pool-wide compliance approach. The latter would necessarily entail complex compliance planning and permitting requirements pursuant to section 408 of the Act, possibly involving multiple permitting authorities.

d. *January 30.* EPA is proposing that all allowance transfers must be submitted for recordation by January 30 of the calendar year following the calendar year for whose SO_2 emissions limitation requirements an allowance is to be applied.

In proposing the January 30 date, EPA concluded that this would provide units with ample time to transact and submit allowance transfers. At the same time, section 411 of the Act and part 77 of today's proposal require units with excess emissions to submit offset compliance plans by no later than 60 days after the end of the year in which they generated excess emissions. Accordingly, a January 30 allowance transfer deadline affords EPA one month in which to record closing transfers and to resolve any associated errors, and offers violating units one month from the submission of transfers to complete and submit excess emissions offset plans, if necessary, prior to the excess emissions offset planning deadline.

EPA expects that the vast majority of allowance transfers will occur before the end of the calendar year, since utilities customarily rely on forward planning. In fact, the spot market for allowances is likely to comprise only a small percentage of the total number of transfers. In addition, pursuant to proposed part 75, utilities will be able to anticipate, and then to confirm, their total actual annual emissions well in advance of the January 30 deadline. Throughout the course of each year, continuous emissions monitoring, required under section 412 of the Act and part 75, will provide hourly emissions data. As a result, utilities will be able to project their total annual emissions throughout the course of the year. For the same reason, units will be able to determine their actual annual emissions literally the day after year-end, January 1.

EPA believes it prudent to preserve a one-month period after final allowance transfers are to be submitted and before excess emissions offset compliance plans under part 77 are due. During this month EPA will be required to record all properly submitted transfers to compliance subaccounts. If a large volume of transfers are submitted there may be a delay between submission and recordation for any given transfer. During that month, authorized account representatives will be required to determine the accuracy of any recordations and to submit error claims (as provided in proposed subpart C) which EPA, in turn, will have to resolve. Again, final recordation in compliance subaccounts will have to be completed on a timely basis so that, where necessary, part 77 excess emissions offset plans and excess emissions penalty payments can be submitted by the statutory 60-day deadline.

In most cases, utilities with units with excess emissions will know well in advance of the 60-day deadline of their need to pay penalties and prepare excess emissions offset plans, regardless of the allowance transfer deadline. Others, however, will be in non-compliance essentially as a result of their failure in last minute attempts to obtain allowances. For these units, allowing a month after the allowance transfer deadline to reckon their penalty liability and prepare offset plans is crucial.

EPA considered and rejected extending the allowance transfer deadline to February 15. Because continuous emission monitors will provide utilities with hourly emissions data, affected sources will be able to plan for and pursue allowance transfers beginning sometime before the end of the calendar year and certainly before the proposed January 30 deadline for recording allowances. In addition, a February 15 allowance transfer deadline would leave only 15 days before the deadline for submission of excess emissions penalties and offset plans required under part 77. During that period, EPA would have to record transfers, notify the authorized account representatives as to whether the trades are approved or rejected, and, if necessary, process error claims. EPA would then have to make allowance deductions from compliance subaccounts to account for a unit's emissions for the year in order to determine compliance, and to identify those units with excess emissions. EPA does not believe that a 15-day period would offer sufficient time to carry out these functions reliably, particularly in Phase II of the program when the number of affected units will increase to over 2,000. Moreover, those units who failed at the last minute to secure sufficient allowances would not have sufficient time to prepare an excess emissions offset plan.

At the same time, EPA believes that the marginal advantages offered utilities by extending the allowance transfer period to 45 days instead of 30 are slight. EPA anticipates that the vast majority of compliance strategies, including allowance transfers, will be implemented on a long-term, multi-year basis. Few will involve short-term, end-of-year decisions to which an additional 15 days, beyond the initial 30 proposed today, would be critical. In addition, allowance "insurance" pools could be established on a long-term basis to accommodate end-of-year contingencies expeditiously and at low cost. To compete with such pools, spot market sales would likely also be driven down to a relatively low-cost.

EPA also considered a January 15 allowance transfer deadline. EPA is not proposing this transfer cutoff date because confining end of year transfers to 15 days, as opposed to 30 days, would provide little, if any, enhancement of EPA's administrative efforts. Adding 15 days to the period between the allowance transfer deadline and the deadline for submission of emissions offset plans is also not critical, either to EPA's enforcement efforts or to units'

development of excess emissions offset plans. Any units with substantial excess emissions would already be aware of their circumstances prior to the end of the calendar year, and could begin developing their offset plans well ahead of the deadline for submitting such plans, regardless of the date of the allowance transfer deadline. In addition, the time needed to consummate allowance transactions even if initiated well before year-end may warrant more than 15 additional days after year-end, thus justifying a longer extension.

Nevertheless, EPA requests specific comment on the advisability of a January 15 allowance transfer deadline. Because utilities will have the benefit of long- and medium-term compliance planning as well as nearly up-to-the-hour cumulative emissions data, they will have ample opportunity, well before the end of each calendar year, to determine their need for additional allowances and to acquire any such allowances. With the planned adoption by EPA of electronic methods for the submission of allowance transfers, transfers will be able to be submitted, received, and recorded in a minimal amount of time. These factors suggest a need for only a *de minimis* transfer deadline extension beyond the end of each calendar year. At the same time, compared to a January 30 deadline, a January 15 deadline accelerates the time within which (i) final transfers can be recorded; (ii) errors can be resolved; (iii) allowances can be deducted from compliance subaccounts for purposes of determining compliance; (iv) compliance subaccounts can be replenished with allowances from the pending future year subaccounts; and (v) transfer activity for what is now the current year can be recorded in the replenished compliance subaccount. These actions can only be completed consecutively and the sequence cannot begin until the allowance transfer deadline passes. It is in light of these considerations that EPA seeks comment on a January 15 allowance transfer deadline.

Finally, EPA considered a December 31 transfer deadline coinciding with the calendar year compliance requirements mandated by the Act. EPA is not proposing this deadline because it would not provide the additional flexibility of an extended allowance transfer period. Nonetheless, EPA requests specific comment on the advisability of a December 31 deadline. Such a deadline would provide more time for final transfers to be recorded and any errors resolved before offset plans and excess emissions penalties are due. In addition, deductions for compliance and replenishment of compliance subaccounts could occur earlier.

8. Deductions for Compliance

Once all recordations are made in compliance subaccounts, EPA is proposing to deduct from each unit's compliance subaccount allowances equal in amount to the unit's reported SO_2 emissions during the preceding calendar year. As already suggested in the previous discussion of the use of identifying numbers for allowances, EPA is sensitive to the potential importance, in promoting cost-saving market activity, of differential tax and ratebase treatment for particular allowances. Accordingly, EPA is proposing to permit the authorized account representative for each unit to specify, by no later than the January 30 allowance transfer deadline, which allowances are to be deducted from the compliance subaccount. To the extent that units may be holding allowances with differing cost bases, this could enhance units' abilities to demonstrate what they believe to be their true compliance costs for tax and ratebase purposes.

In the event that an authorized account representative failed to specify particular allowances for deduction, the proposed default rule would operate on a "first-in, first-out" (FIFO) accounting basis. EPA would deduct first those allowances with the earliest compliance use date originally allocated for the unit and recorded in its compliance subaccount. Then, continuing with those with the earliest date of recordation, EPA would deduct any remaining allowances that were originally allocated for other units and subsequently recorded in the unit's compliance subaccount, until either no more allowances remained in the subaccount or total deductions equalled the unit's SO_2 emissions tonnage during the preceding year.

EPA is proposing the "first-in, first-out" or FIFO method for its default rule because EPA believes this approach to be most accommodating for the financial needs of utilities. The FIFO inventory accounting system is a common method used by industries for financial purposes of determining consumption of inventory, and it may reflect the preferable approach for tax purposes for affected units. If so, such a default rule would minimize the need for utilities to take affirmative steps in notifying EPA as to which allowances are to be deducted. Instead, the majority of utilities could rely on the default rule as offering the preferred method of deduction.

EPA also considered and rejected for its default rule the "last-in, first-out" or LIFO inventory accounting method. Under the LIFO method, EPA would begin its deduction of allowances with those most recently acquired, starting with those in the unit's compliance subaccount that had been allocated originally for other units and transferred to the unit's account. Then, continuing with those most recently allocated for the unit, EPA would deduct any remaining allowances until either no more allowances remained in the subaccount or total deductions equalled the unit's SO_2 emissions tonnage during the preceding year. Although LIFO is a widely used inventory accounting method, it did not appear to offer any significant financial or tax advantages to utilities and therefore would be less likely to be elected as a deduction method by affected units. Therefore, its selection by EPA as a default method would encourage utilities to notify EPA of the specific allowances in their compliance subaccounts they would prefer to be deducted for compliance purposes. Such notification would add to the compliance burden of the utilities, without offering any significant benefits to EPA on its own merits as a method of deduction.

EPA requests comment on the default methods for deducting allowances from compliance subaccounts and the advantages and disadvantages each method would offer to affected units.

9. Common Stacks

Where more than one unit's emissions are ducted through a single stack with a single emissions monitor, reported data will reflect the emissions of all units connected to the stack without differentiating each unit's emissions. For this reason § 75.11(a) and § 72.50, also proposed today, provide that in those cases, EPA will require the units to submit a common stack plan and will aggregate the units' emissions and allowances for purposes of determining compliance. Accordingly, proposed part 73 includes a parallel provision.

To conform to the unit-by-unit allocation provisions of the Act, EPA will allocate allowances and maintain separate accounts for each unit individually. Each year, to determine unit compliance, EPA will aggregate all allowances in the units' compliance subaccounts and then deduct from the aggregated total according to the same methods available under § 73.35(b) to affected units with their own emissions stacks. EPA will accept Compliance Deduction Forms from a unit's authorized account representatives that

specify the allowances to be deducted for compliance purposes for their units. When no allowances are specified, EPA will deduct allowances from the aggregated accounts in the "First-in, First-out" order, as described in § 73.35(d), without regard to accounts of origin. Any allowances remaining after the deduction will be reallocated on a per capita basis. EPA has concluded that it is unnecessary to apply a more complex pro rata approach for reallocating remaining allowances, since utilities themselves can retransfer allowances between and among units after determining for themselves a more appropriate method of apportioning remaining allowances.

10. Deductions for Units Subject to Amended Phase I Substitution and Compensating Unit Plans

Proposed Part 72 authorizes amendments to Phase I Substitution plans and Compensating Unit plans to remove the designation of substitution or compensating units originally subject to such plans. Since allowances would be allocated for such units upon approval of the initial plan, proposed part 72 requires the deduction from the units' accounts of allowances equivalent in number and compliance use date to those originally allocated for the units. Proposed part 73 includes a parallel provision effecting such a deduction.

11. Deductions for Excess Emissions

Section 411(b) of the Act provides: "The Administrator shall also deduct allowances equal to the excess tonnage from those allocated for the source for the calendar year, or succeeding years during which offsets are required, following the year in which the excess emissions occurred." To meet this requirement, EPA is proposing that unless the designated representative has otherwise provided in an approved excess emissions offset plan, EPA will choose the order of the unit's allowances to be deducted. Following the "replenishment" of the unit's compliance subaccount with allowances from the future year subaccount corresponding to the year following the excess emissions, EPA will deduct from each such unit's compliance subaccount allowances in an amount equal to the unit's excess emissions.

By allowing the authorized account representative for a unit with excess emissions to include in its offset plan a specific designation of offset allowances, EPA is enabling the utility to determine the most cost-efficient way for it to come into compliance. An approved excess emissions offset plan may specify which allowances should be deducted and when during the course of a year they should be deducted from the unit's account to offset its excess emissions. As is provided in part 77, the offset plan may also specify that the allowances be deducted from a substitution unit's account. In the absence of such a plan, the unit with excess emissions must accept EPA's method of deducting allowances.

For those units governed by a common stack plan and monitored at a common stack and whose aggregated emissions exceed the aggregated number of allowances held by the units in their compliance subaccounts, EPA proposes a similar method of deducting excess emissions offset allowances as described for a single unit—that is, permitting the authorized account representative to identify specifically the allowances for deduction in the mandated offset plan. If no such identification is included in the source's plan, EPA would simply treat each unit's individual compliance subaccounts as a comprehensive compliance subaccount and their future subaccounts as comprehensive future subaccounts for the purposes of deducting offsetting allowances. Units monitored at a common stack are in any case deemed to be jointly and severally liable for excess emissions pursuant to § 75.11 and § 72.50. EPA thus would aggregate the units' subaccounts and deduct the appropriate number of allowances. Any allowances remaining in the aggregated subaccount would be reapportioned back to the units' individual subaccounts on a per capita basis. The utilities themselves could retransfer allowances between and among the units after determining for themselves an appropriate method of apportioning remaining allowances.

12. Banking

Section 403 of the Act requires that allowances not used for purposes of compliance be carried forward and added to allowances allocated for use in subsequent years. Following any deductions made for compliance purposes, EPA is proposing to retain in the compliance subaccount any allowances not deducted in offsetting the unit's SO_2 emissions. EPA believes this is the most simple and efficient way to identify unused allowances to be carried forward and added to allowances allocated for use in subsequent years. EPA sees no reason to require special procedures requiring further affirmative activity by the authorized account representative in order to effectuate banking.

13. Account Error and Dispute Resolution

EPA is proposing to allow an authorized account representative to notify EPA in writing in the event that he or she claims an error in the tracking system account. In order to prevent frivolous or unfounded claims, EPA would require all claims be made in writing, and include: (a) A description of the error; (b) a proposed correction of the error; (c) any supporting evidence of the error; and (d) certification by the authorized account representative. The submission of all claims in writing also establishes a record of such claims and the responses made, which should prevent additional disputes concerning inaccurate recall if suggested corrections, responses, or disputes are conveyed through a less permanent medium, such as oral conversation.

To limit unfounded claims further and to establish finality for compliance purposes, the submission of all claims of error must be received by EPA within 20 business days, if the time period is marked from the date of submission of the transfer for recordation, or by no later than 10 business days, if the time period is marked by the date of EPA's transmission of the notice of recordation of the transfer. Furthermore, any claim of error concerning allowances in a compliance subaccount must be received by no later than 15 business days after the allowance transfer deadline for the compliance year in order to allow sufficient time for EPA to record those transfers submitted immediately before the allowance transfer deadline and for the authorized account representative to receive notification of the transfer and then to submit a claim of error. EPA is further proposing, however, to accept claim of errors submitted following these deadlines upon a showing by the authorized account representative of good cause for the delay.

Following receipt of any claim of error, EPA is proposing to respond in writing to the authorized account representative. Such response would include: (a) The determination made or action taken; and (b) reasons for such action. In order to avoid a drawn-out appeals process in the resolution of claims of error, EPA is proposing that all EPA decisions concerning a claim be within the Administrator's sole discretion. This will help to ensure the orderly functioning of the allowance system by quickly establishing finality and certainty. Furthermore, EPA recognizes that units will want to have their account balances reflect their

official holding of allowances usable for compliance purposes in order for them to be able to specify the allowances EPA should deduct for compliance purposes and to continue with the unit's cost-minimizing compliance strategy. Designated representatives will also need to know with certainty if their units are in compliance with the SO_2 emissions limitation requirement to be able to submit an excess emissions offset plan to EPA for approval in a timely manner.

EPA is proposing that, following the authorized account representative's receipt of the Administrator's decision on the error claim submitted to EPA, the authorized account representative could, if desired, resubmit the claim and all relevant supporting documentation for reconsideration by the Administrator. EPA proposes each claim of error be restricted to one resubmission, in order to prevent burdensome or trivial error claim submission.

EPA requests comment on whether to afford an administrative appeals procedure for such claims as is provided in part 72 for permit action appeals. In addition, EPA requests comment on whether to afford such appeals procedures in connection with other aspects of this part.

14. Public Availability

EPA is proposing to make all information in the Allowance Tracking System accounts available to the public. Initially, EPA will make written records available. EPA is, however, developing a system of electronic access and will prescribe the appropriate methods of such access in the future, following public notice. EPA believes it is important to make account information publicly available for several reasons.

First, allowance market participants need to be provided with some basic market information. For example, the authorized account representative information will enable market participants to make contact with potential trading partners or to check the accuracy of account information. Absent such information, allowance trading activity could be inhibited or involve higher transaction costs.

Second, the public, including special interest groups and researchers as well as private citizens, will have a strong interest in the environmental performance of the program. For example, they may want to see how much SO_2 units are emitting and the number of allowances units have in their accounts.

EPA will develop an electronic access system because electronic availability of information reduces the need for paperwork, reports, or submissions, and increases the speed with which information can be obtained. With an electronic system, authorized account representatives will be able to save time when they submit reports to EPA, and know much sooner when EPA has recorded an allowance transfer.

C. Allowance Transfers

1. Recordation of Transfers

Section 403 of the Act requires a transfer of an allowance to be certified by the parties to the transfer and received and recorded by the Administrator before it can be effective. Accordingly, as discussed above, EPA is proposing that no allowance may be used for purposes of a unit's compliance until the allowance is recorded or properly submitted for recordation. Of course, this must occur by the allowance transfer deadline for the allowance to be used for compliance in the current calendar year in the unit's account. However, it will be up to the parties to decide when to record a transfer, since EPA is not proposing any other requirements as to when or if a transfer must be submitted for recordation.

Some commenters believe that EPA should require that all transactions involving allowances, including options and other transactions involving the purchase of allowances in the future, be submitted for official recordation in the Allowance Tracking System (ATS). In addition, they believe that EPA should require that a notice of the transaction be submitted to EPA within a certain number of days of the transaction becoming legally binding between the parties for the transfer to be acceptable for official recordation in the ATS. They assert that the allowance market will not operate efficiently unless all transactions are recorded promptly in the ATS, which, they imply, may be the only readily available and affordable means of identifying transactions affecting ownership of allowances. Such complete and timely information is necessary, they argue, to assess supply and demand of allocated allowances, to determine what the market price might be, and to identify possible buyers or sellers of allowances. Such commenters believe that public display of every transaction may also be useful to identify possible hoarding activities which, they fear, may severely restrict the availability of allowances for compliance purposes.

EPA rejected this approach because it believes there is sufficient incentive for the private sector to develop systems to transact, record, and disseminate pertinent information on complex, strategic transactions in a timely manner without constraining parties' flexibility concerning transfers of allowances. In fact, the private sector is most likely better able than EPA to record and disclose such transactions in a timely, proficient manner that would help maximize economically efficient decisions. Already, the Chicago Board of Trade and other exchanges have announced they are exploring establishing commercial exchanges for allowances and allowance-based financial instruments. Through such exchanges distilled price information and information on allowance trading would be broadly disseminated. Centralizing recordation of all transactions through EPA could impose higher, unnecessary costs on the market resulting from processing delays due to a greater volume and complexity of transactions to be recorded and slower notification of results. In addition, forcing such public disclosure of all allowance transactions may reveal sensitive business decisions about a firm's trading strategy that the firm may prefer be kept secret to maintain bargaining position in the market.

For these reasons, EPA is proposing to record only those transactions that effect the official transfer of an allowance at the time the transfer is submitted to EPA for recordation. Transactions that do not meet this requirement for direct and timely transfer of allowances, such as options and futures on the rights to allowances, would not be recorded in the ATS. If EPA required immediate recordation of private, commercial transactions involving allowances, EPA would not have the capability to enforce such a requirement. EPA would not be able to identify, or even to define, all private commercial transactions affecting allowances or pinpoint when they took place, limiting EPA's ability to enforce the requirement for timely recordation. Submittal of the transfer for recordation is not necessary for a commercial contract to be legally binding, and commercial transfers may occur without EPA's knowledge. Parties determined to postpone recordation might be able to structure transactions to circumvent the requirement, by avoiding the definition of "recordable" transfer. Apart from the condition that allowances must be recorded in a unit's account to be useable for compliance, EPA does not believe the Act contemplates that EPA penalize parties to a transfer for their failure to submit transfers to EPA for recordation. To refuse to record a transfer because it was "untimely" (again, apart from the allowance

transfer deadline) would only undermine the purpose of the ATS as a credible recordkeeping system of current holdings of allowances.

Even in the absence of a forced recordation requirement, the transferee has sufficient incentive to report the transfer promptly to EPA for official recordation to secure the allowances for compliance purposes. Timely recordation is important to the transferee simply to ensure that the allowances being transferred have not already been claimed by a subsequent transfer undertaken by the transferror. Furthermore, the transferee might also need such proof of holding in order to sell the allowances to another party.

2. Price and Other Terms of Transfers

Some commenters believe EPA should request and record the cash price paid and other terms of the contract (such as coal deliveries or power purchase arrangements) provided with each transfer of allowances. They argue that such information must be widely available to the market participants to determine whether the price offered for allowances is competitive, and to choose the most economically efficient compliance strategy. The growth of the allowance market, they argue, may be significantly hindered without dissemination from a centralized repository, such as EPA, of information necessary for an affected unit to choose a compliance strategy. Although the private sector may have incentive to collect and disseminate such price information, the commenters believe it will be costly and limited in supply and scope. EPA, they argue, is in a unique position to collect and disseminate this information.

Although nothing in the Act prohibits EPA from collecting and reporting price and contract terms for allowance transfers, EPA proposes that the Agency not request and record the price and terms of an allowance transfer for several reasons. First, contract terms are likely to be complicated and tailored to the individual parties' needs, which would be difficult for EPA to record in a consistent, concise, and meaningful format. Second, any attempt by EPA or those participating in the transfers to calculate a numerical cash-equivalent price paid for an allowance incorporating other, non-cash terms would likely yield an imprecise result, and would not be useful or reliable for other market participants. At the same time, a single reported price paid for an allowance that did not contain the value of the other terms may also be misleading because any additional terms would most likely impact the actual price paid for the allowance.

More importantly, EPA believes that price and contract term information will be available through other public channels, along with other details about trading. Price information will be available from EPA auction results, while price and contract terms may be reported to the Federal Energy Regulatory Commission and State public utility commissions. Private markets will also supply useful price and quantity information through brokers and centralized information networks, as is done in financial and commodity markets. For example, the National Association of Security Dealers Automated Quotations System (NASDAQ) supplies timely price and volume information for the over-the-counter stock market, and multiple listing services provide location, amenities, and price information for regional real estate markets. Data resource companies also may collect the allowance transaction information, as exemplified by the variety of publicly displayed reportings of New York Stock Exchange and American Stock Exchange activities. Details on allowance trades would most likely be reported in trade newspapers and magazines.

Several commenters have suggested that some market participants would refuse to report the price and terms of allowance transfers to EPA, or delay the reporting of the transaction itself, because of the sensitivity of the information or its link to the competitiveness of their firms' operations. EPA does not have clear authority to refuse to record the transfer if the parties did not disclose the price or terms.

Even if EPA could compel the parties to disclose price and terms and honored their request that the information be held as confidential business information, EPA would not be able to guarantee its confidentiality. If challenged in court by outside parties under the terms of section 114 of the Act or of the Freedom of Information Act (FOIA), EPA would be required to prove that the price and other terms of consideration associated with an allowance transfer are confidential trade secrets in order to prevent their release to the public. The outcome of such an argument is uncertain at this point, especially if such data is publicly reported to state-Public Utility Commissions. Even publicly reporting this information in masked form through averaging reported prices or not publishing names at the party's request would not alleviate the risk of potential disclosure of all reported terms under FOIA. EPA's general policy is to make publicly available all information it collects, unless such information is expressly prohibited from release by statute or EPA believes the withholding of such information is authorized under FOIA; EPA would have difficulty justifying a decision not to release information it has collected for the purpose of disseminating a distilled version of the same information.

Consequently, some commenters argue that EPA's inability to guarantee fully the confidentiality of information required for recordation of price and contract terms would discourage recordation of transfers with EPA, or even deter market participation. This concern does not appear to be well-founded in view of EPA's firm expectation that the market itself will foster information-gathering mechanisms, as will PUCs and FERC in carrying out their traditional regulatory duties.

Finally, many members of the public predict that utilities' tendency to use long-term forward contracts could give rise to a standardized, exchange-traded futures instrument. They argue that the fungibility of allowances, coupled with potential price volatility resulting from factors such as variations in energy demand over time, development of new technology and need for allowances by new units, render allowances very similar to other commodities for which such futures trading exists. If so, active futures exchanges could enhance the efficiency and liquidity of the allowance market by distilling a single uniform price for allowances. It is through mechanisms such as a futures exchange, therefore, that EPA believes the public would get critical information, which would be of superior value to any that EPA could collect by mandate. As discussed above, the already announced efforts of the Chicago Board of Trade and other exchanges could lead to an allowance-based financial exchange that would disseminate broadly distilled price information. EPA firmly believes that the mandatory, public collection of information concerning allowance-related transactions could inhibit the development of such exchanges, which typically rely on anonymity and a high volume of activity to succeed.

3. What Constitutes a Valid Transfer

EPA proposes to record only those transfers that meet the following criteria:

a. The transfers are authorized and certified (in writing or by other

authorized means) by the authorized account representatives for both the transferror account and the transferee account;

b. Each allowance cited in a request for transfer must be listed in the subaccount specified by the authorized account representative of the transferror account;

c. The allowance requested for transfer was not allocated for the unit pursuant to the provisions of § 72.44, for purposes of a repowering compliance plan, or pursuant to part 74 (to be proposed and promulgated at a later date), and made available as a result of reduced utilization or shutdown at the unit;

d. The allowance requested for transfer is recorded in the compliance subaccount or the current year subaccount and is to be transferred to another compliance subaccount or current year subaccount, or is recorded in a future year subaccount and is to be transferred to another future year subaccount for the same year; and

e. The EPA Allowance Transfer Form submitted to EPA has been completed properly.

EPA proposes to require this information to be submitted with each transfer because such information is necessary to maintain proper records for each account holder in the ATS. The submittal of the authorizing signatures of the authorized account representatives is necessary to verify that the transfer request is submitted with their full knowledge and permission.

A submitted transfer request that is incomplete will not be recorded and will be returned to the authorized account representative with notification of the reason that it was not recorded. If a transfer request lists some allowances, identified by their serial numbers, that are not actually in the account from which they were to be transferred, or are prohibited from transfer to another account (i.e., those allocated for the unit pursuant to § 72.44(g) in connection with a repowering compliance plan, or those allocated pursuant to part 74 and made available as a result of reduced utilization or shutdown at the unit), only those allowances listed in the request that are in the account and are not prohibited from transfer will be transferred and EPA will notify the authorized account representative of the reason that the transfer of the other allowances was not recorded.

If a transfer, such as that of all of a unit's allocations in perpetuity, includes allowances whose compliance use date is more than 30 years after the year in which the transfer is submitted, EPA will include in the relevant transfer accounts an instruction to record the transfer, as soon as the future subaccount "appears" in the ATS. As will be the case for transfers recorded as final in existing future year subaccounts immediately upon submission, the recordation-of-transfer instructions will be permanent and irrevocable. Only the submission of a new transfer request will affect any further transfer of those allowances. Directions for identifying such allowances by serial number will be provided through public notice at a future date.

4. Prohibited Transfers

a. *Transfers of allowances between subaccounts of different years.* Aside from emissions offsets by either allowances banked from previous years or certain allowance allocations authorized for 2000 through 2009, the Act prohibits emissions exceeding 8.95 million tons per year. Consequently, the Act also requires EPA to prohibit the use of any allowance prior to the calendar year for which the allowance was allocated (section 403(g)). EPA is effectuating this requirement in part by prohibiting transfers of allowances from a subaccount for a later year to a subaccount from an earlier year. Such a transfer would violate the annual emissions cap. If EPA permitted the use of a future allowance before its compliance use date, the cap on emissions would be violated by permitting emissions before they were authorized to occur, without their having been offset by an emissions reduction in a previous year.

The design of the subaccount system—separating allowances into future year subaccounts based on each allowance's compliance use date—prevents transferring an allowance from one future year subaccount to that for a later year. If that were to occur, the allowance would only be available for purposes of compliance in the later year corresponding to the year of the subaccount; it would no longer be available in the earlier year of its compliance use date. In fact, allowance holders can accomplish the result of transferring allowances from one account's earlier year subaccount to another account's subaccount for a later year much more simply. After the allowance is transferred to the transferee's subaccount for the same year, the transferee can simply bank the allowance for use in a future year and do so while retaining the flexibility of using the allowance as early as its compliance use date.

b. *Transfers from Units with Excess Emissions.* The Act specifies that it is unlawful for any affected unit to emit sulfur dioxide in excess of the number of allowances held for that unit for that year (section 403(g)). In addition, section 411 of the Act and part 77 require that EPA deduct allowances from those allocated for the unit for the year or years following the year in which the excess emissions occurred, in an amount equal to the unit's excess emissions. To ensure that it can implement this requirement, EPA proposes the following: for the account of an affected unit with excess emissions whose emissions offset plan has not yet been submitted and/or approved, EPA would prohibit the transfer of an amount of allowances in the unit's compliance subaccount needed to offset the excess emissions that occurred during the preceding year. Once the emissions offset plan is submitted and approved by EPA, the allowances subject to the prohibition may be transferred, if any remain after deductions are made for excess emissions.

By imposing a prohibition on transfers of a violating unit's allowances, EPA ensures its ability to meet the requirements of the Act directing it to deduct allowances for excess emissions. By limiting the prohibition only to those allowances necessary for compliance and not to the entire account balance, EPA maintains the unit account holder's flexibility in its trading activity. However, because there may be a period in each year during which the designated representative may be aware that a unit has excess emissions before the Agency does, a unit's authorized account representative will be violating section 414 of the Act and part 73 if he/she submits a transfer for recordation in violation of this prohibition, regardless of EPA's action in recording the transfer.

c. *Transfers involving allowances prohibited from transfer.* The Act specifies that allowances allocated for a unit for an approved repowering compliance plan can not be transferred (section 409(c)). Allowances allocated to a non-affected source of SO_2 under the "opt-in" program requirements (to be promulgated later as part 74) and made available as a result of reduced utilization or shutdown are also prohibited from transfer. EPA proposes to mark such restricted allowances in the Allowance Tracking System to ensure that EPA can determine whether any allowances included in a transfer request are subject to such restrictions.

5. Submission of Transfers

EPA proposes to require that the following information, at a minimum, be provided to EPA on an Allowance Transfer Form when authorized account representatives request EPA to transfer allowances between accounts:

a. The numbers identifying both the transferor's and the transferee's accounts;

b. Specification of the compliance use date and serial number for each of the allowances to be transferred;

c. Signatures of the authorized account representatives of both the transferor's and transferee's accounts, certifying the information submitted to record the transfer and that EPA's recordation of the transfer of allowances does not limit the affected unit's obligation to comply with annual emissions limitation requirements for any year; and

d. Where the transferee's account has not been established in the ATS, information required pursuant to the requirements in § 73.31 for establishing a new account.

EPA believes that allowing the parties to a transaction to determine when to submit the Allowance Transfer Form to EPA to request recordation of a transfer, and consequently to determine when the transfer of allowances will be recorded, provides the greatest versatility and liquidity to the market. The form also serves as a legal record of the instructions for transfer, authorized by both parties, as indicated by their signatures.

The information requested on the Allowance Transfer Form is the minimum amount necessary for EPA to record the transfer. Specification of the compliance use date and serial number of each of the allowances requires the transferor to direct which allowances are to be transferred and from which subaccount, without which information EPA cannot record the requested transfer. Relevant account numbers and authorizing signatures ensure that the transfer is being conducted under full knowledge of the account owners, and that, notwithstanding EPA's action on the submitted transfer, the affected unit is still obligated to comply with its annual emissions limitation requirements.

EPA expects to record all submitted transfers that meet the requirements of the Act and part 73. EPA will not review a unit's reported emissions for purposes of validating a transfer. The burden of responsibility for meeting compliance requirements is on the unit. Authorized account representatives would be required to certify acknowledgement of this responsibility when they submit transfers for recordation in order to underscore that EPA's recordation of the transfer will in no way be a basis for subsequent defenses to enforcement on the grounds that EPA's recording of a transfer nullified this obligation.

Today's proposal contemplates the use of electronic methods for submitting allowance transfers. EPA is evaluating various potential approaches to electronic transmission of allowance transfers, using either on-line access to the system (whereby the authorized account representatives would record the information directly into a system maintained by EPA) or Electronic Data Interchange (EDI—ANSI X12) standards for data exchange. EPA requests comment on these options. EPA will announce the selected alternative method(s) under Agency guidance provisions at a later time.

6. EPA Recordation of Transfers

EPA proposes to record an allowance transfer in the ATS following receipt of the Allowance Transfer Form, by deducting the allowance from the specified transferor's subaccount and adding it to the transferee's subaccount of the same year, provided that EPA has determined the transfer to be valid. Valid transfers would be recorded within five business days after receipt of the Allowance Transfer Form by EPA, except, as described below, during the time period immediately following the allowance transfer deadline. A maximum of five business days is a reasonable period of time for EPA to determine the validity and completeness of the transfer instructions and provides sufficient certainty to the parties to the transfer upon which to plan compliance and subsequent allowance transactions. In any event, EPA will seek to minimize the time needed to record transfers.

In the period immediately following the allowance transfer deadline, however, transfers of allowances to and from compliance subaccounts will be recorded after EPA has recorded the requisite transfers and deductions for compliance purposes, listed in § 73.34 and § 73.35, to establish the correct balance of allowances in the replenished compliance subaccount. EPA considers this order of recordation of transfers affecting a unit's compliance subaccount to be necessary so that the compliance subaccount can be "closed" with respect to allowances applicable to emissions limitation requirements for the preceding year, and then replenished with banked and current year allowances.

7. Notification

EPA proposes to issue written notice, confirming the recordation of the transfer in the ATS, to the authorized account representatives of both the transferor's and transferee's accounts, within five business days following recordation. The notification would contain the account numbers of the transferor and transferee, the identifying numbers of the allowances transferred, and the date the transfer was recorded in the ATS. EPA would issue the notice in writing by United States mail, or other methods prescribed following public notice, within five business days of the transfer's recordation in the ATS. EPA believes that notification of the recordation of the transfer to the authorized account representatives is necessary to assure parties of the effectuation of the submitted transfer by means of its official recordation in the ATS.

8. Non-Recordation of Transfers

EPA proposes that transfers submitted to EPA that EPA determines to be invalid would not be recorded in the ATS. EPA believes that, because EPA's ATS is the official record of allowance transfers, EPA should not record transfers that do not meet the requirements of the official record-keeping system.

EPA proposes that when EPA receives an Allowance Transfer Form requesting recordation of the transfer in the ATS and determines the entire or a part of the transfer to be invalid, EPA would issue a notice of the non-recordation of the entire transfer or the invalid part of the transfer in the ATS to the authorized account representatives of both the transferor's and transferee's accounts within five business days following EPA's determination of the incomplete or invalid status of the transfer. The notification would contain the account numbers of the transferor and transferee, the identifying numbers of the allowances requested for transfer that were not transferred, and the reasons that the transfer for those allowances was not recorded. Upon rectifying the errors, the parties may then resubmit the transfer or its remaining unrecorded portions to EPA for recordation.

9. Electronic Reporting

EPA intends to design an electronic format that will allow authorized account representatives to submit their allowance transfer and allowance deduction notifications to EPA electronically and will provide immediate access to view Allowance

Tracking System accounts. At the very least, this electronic communication would be available as an option for anyone wishing to use it. EPA requests comment on whether the Agency should mandate electronic reporting requirements for all Allowance Tracking System functions. The benefits of electronic reporting include speed and enhanced certainty. A potential drawback, however, is that such a mandate could create a barrier to participation in the allowance market and use of the ATS for a person without access to the technology, such as a personal computer and modem, that would be necessitated by an electronic format. If so, such a mandate could run afoul of the authorization in section 403(b) of the Act for "any person" to transfer allowances and of the policy underlying the provision of promoting liquidity in the market.

D. Energy Conservation and Renewable Energy Reserve

1. Authority

Section 404(f) of the Act requires the Administrator to establish a Conservation and Renewable Energy Reserve (the "Reserve") of 300,000 allowances for distribution to electric utilities engaging in energy conservation or in renewable energy generation. The Reserve is to be created by deducting from total annual Phase II allocations 30,000 allowances per year in each of the first ten years of Phase II. Utilities may begin applying for allowances from the Reserve in 1993, one year following promulgation of the regulations, and may continue to apply until all 300,000 allowances have been allocated or until the year 2010 if any remain. The allowances will not be restricted by a compliance use date, but will be allocated for emissions avoided through the use of qualified renewable generation or as a result of qualified energy conservation measures initiated after January 1, 1992, and before the earlier of December 31, 2000 or the date on which any unit owned or operated by the electric utility becomes affected under title IV of the Act.

The allowance allocation for applicants will be determined by a calculation specified in the Act that is based on a national "average" of emissions avoided through the use of a conservation measure or through generation from a renewable source of electricity. As the Act prescribes, EPA will promulgate regulations governing the operation of the Reserve by May of 1992, 18 months after enactment of the Amendments. The regulations creating the Reserve will be promulgated with the Phase II allocation regulations, no later than December 31, 1992.

2. Qualifying Criteria

The Act identifies a number of qualifying criteria which applicants must satisfy in order to be eligible for allowances from the Reserve, which EPA has interpreted in today's proposal.

a. *Least cost plan.* One of the requirements for receiving allowances from the Reserve is that the applicant must have in place an energy conservation and electric power least cost plan for meeting future electric needs. The Act requires the least cost plan to include an evaluation of a full range of resources, including but not limited to new power supplies, energy conservation, and renewable energy resources, in order to meet expected future demand at lowest system cost. This provision in the Act will assist in assuring state regulatory authorities and consumers that the full range of options—demand-side (i.e., use by electricity consumers) efficiency improvements as well as supply-side (i.e., generation by the utility) efficiency improvements—are being considered to meet the electric power needs of ratepayers.

There are as many definitions of least cost planning as there are States that have adopted it. While the definitions and provisions vary, the elements common to such plans include:

(1) The utility must outline a plan for meeting future demand at the lowest system cost;

(2) In so doing, the utility must consider explicitly both supply-side and demand-side resources; and

(3) The utility must submit the plan to the regulatory commission (or ratemaking authority), if applicable for review and public comment.

The definition and applicable requirements of a least cost plan proposed today are consistent with the requirements outlined in the Act, but allow the States flexibility in implementing least cost planning criteria. The proposed definition identifies four key elements: (1) Plan preparation; (2) public review; (3) regulatory oversight; and (4) implementation. As required by the Act, the state regulatory authority or entity with ratemaking authority over a utility shall certify in the application that the least cost planning requirements, as stated above, have been satisfied.

In addition, the proposed definition explicitly notes that consideration of social and environmental costs external to the utility's direct costs of resource investments (i.e., externalities) is acceptable, but not required. This is intended to allow for the full variety of State integrated least cost planning requirements, many of which include consideration of externalities. It is possible that the "lowest system cost" for these States differs from what it would otherwise be, absent any consideration of the social and environmental costs of resource decisions. Without this provision, the "lowest system cost" requirement might have the effect of denying eligibility to utilities in States that consider externalities in their least cost planning. Nothing in the Act or the legislative history suggests that the "lowest system cost" criterion be applied in a way that would discriminate against utilities in States that consider externalities. Accordingly, EPA believes that in the absence of a statutory mandate, such a discriminatory effect would defy congressional intent.

b. *Net income neutrality.* The Act requires that utilities applying for allowances for conservation measures must have a rate structure that guarantees net income neutrality. Section 404(f)(2)(B)(iv) of the Act specifies that the net income of an electric utility after implementation of specific cost-effective energy conservation measures must be at least as high as such net income would have been if the energy conservation measures had not been implemented (i.e., that the utility makes as much money on energy saved as energy sold). Accordingly, today's proposal includes this as a requirement for eligibility for an allocation of allowances from the Reserve.

Several general principles guided EPA while developing the proposed definition of net income neutrality as it pertains to utility conservation program implementation:

(1) To eliminate the disincentives to engage in conservation programs;

(2) To create an incentive to engage in conservation; and

(3) To allow flexibility of program implementation.

Historically, utilities have been discouraged from pursuing demand side energy efficiency improvements for a variety of reasons, including uncertain and untimely recovery of costs; lost rate-base revenues; absence of direct profit opportunities; potential increases in electricity rates; and institutional discomfort and unfamiliarity with conservation programs. Under standard practices, the more electricity a utility sells, the more revenue it makes. This poses a major disincentive for actions that would reduce sales, (i.e., conservation programs). Unless explicit

mechanisms are included for full cost recovery of conservation expenditures, a disincentive for conservation will exist. If astutely adopted, full cost recovery can effectively eliminate this disincentive. A number of utilities and State regulatory authorities have worked together to create regulatory frameworks that eliminate these disincentives, and allow a utility to profit from conservation.

In addition, Representative Edward Markey of Massachusetts and Representative Carlos Moorhead of California, the authors of the provision (added by an amendment in the House Committee on Energy and Commerce) stated, "We believe that utilities must be allowed to profit from conservation so that they will aggressively pursue all cost-effective means of improving their customers' energy efficiency" (House Report No. 490, 101st Cong., 2nd sess., part 1, at 675 (1990)). Section 404(f)(2)(B)(iv) of the Act establishes a net income neutrality provision as a prerequisite for an allocation of allowances from the Reserve that is intended both to encourage the development of ratemaking frameworks that put conservation on an equal footing with energy generation and to create incentives for conservation.

The creation of an incentive to pursue demand-side programs can occur in a variety of ways which may include explicitly linking profits to conservation savings. In January 1991, such profit-enhancing programs existed in six States (California, Massachusetts, Nevada, New Hampshire, New York, and Rhode Island); by April 1991 a number of others had joined the ranks and several more are expected to follow in the near future.

The definition of net income neutrality (§ 73.3) proposed today allows States flexibility in establishing rate-making methods or procedures that could be used to satisfy the net income neutrality requirement. For example, commenters have pointed out that requiring strict decoupling of profits from sales may not be necessary if the benefits of cost-effective conservation measures are split between ratepayers and stockholders. The economic incentives instituted as part of shared-savings conservation programs may be enough to encourage utility implementation of conservation programs. Accordingly, the Agency is not proposing a single method—such as compensating for net income lost on a foregone investment in electricity supply—for establishing net income neutrality.

c. *Certification of net income neutrality by the Secretary of Energy.* Section 404(f)(2)(B)(iv) of the Act requires that the Secretary of the Department of Energy (DOE) certify that the State regulatory authority with jurisdiction over a utility's rates and charges has implemented provisions that guarantee net income neutrality. This requirement applies only when the utility is seeking to qualify for allowances on the basis of its implementation of conservation measures. EPA is proposing that applicants apply separately to DOE for net income neutrality certification using Supplement A of the application. EPA will conditionally approve applications pending certification by DOE.

EPA considered, but rejected, sending each application that was the first for each State to DOE to certify that the State had implemented net income neutrality. Once a State had been certified by DOE that it had established net income neutrality in its rate-making, all subsequent applications from utilities from that State would be deemed to have met the requirement of the Act and be eligible for allowances from the Reserve. However, EPA is proposing to reject this option because States sometimes establish different ratemaking structures for different utilities. As a result, each utility's ratemaking structure may be different, requiring separate certification. Because the requirement of net income neutrality is so integral to the success of the Reserve program, and the number of allowances in the Reserve may be scarce in relation to demand, EPA believes it must have certainty that this requirement is being met for each applicant. However, after a utility has received initial certification of net income neutrality, it may reapply, certifying that the same rate structure still applies without needing to go through another full review.

d. *Qualified energy conservation measures.* As part of the regulations governing the Conservation and Renewable Energy Reserve, the Act requires EPA to identify and list "qualified energy conservation measures" (§ 404 (f)(1)(A) and (f)(4)). In addition to establishing such a list, EPA proposes to set forth criteria for identifying additional qualifying energy conservation measures for purposes of the Reserve. The proposed criteria, set forth in § 73.81(a), are consistent with the legislative language. With demand-side programs still in the relatively early stage of development, much opportunity for innovation remains for conservation program design and implementation. From a pollution prevention standpoint, EPA believes it consistent with the Act to foster this innovation. A mere list of already existing "qualified conservation measures" would eliminate opportunities for innovators.

Accordingly, the actual list of qualified conservation measures, which appears in appendix B of part 73, subpart F, is illustrative rather than comprehensive and exclusive. The list was assembled based on extensive comment from utility, regulatory, and industry representatives and includes only those measures currently in use throughout the United States.

EPA proposes that measures not on the list be approved by the State regulatory authority that regulates the rates of the applicant or by the Administrator if the applicant is an electric utility whose rates are not regulated by a State regulatory authority. EPA believes that a State regulatory authority is the appropriate entity to review and approve a conservation measure not listed in appendix B(1) because of such authority's ability to access the cost-effectiveness of the measure. State authorities routinely make such reviews in connection with the review of least cost plans and other review of measures undertaken by utilities. EPA is also proposing the same procedure for renewable energy generation not listed in appendix B(1) for the same reasons stated above.

EPA invites public comment on the potential need and mechanisms for updating the list, as well as on the provisions of proposed § 73.81 for doing so.

EPA is proposing not to include supply-side efficiency improvements in the list of qualified conservation measures. EPA bases this proposal on several factors. The Act's emphasis on net income neutrality reflects an intent to address the potential losses in utility income associated with demand-side conservation measures, thus suggesting congressional focus on demand-side efficiencies. Since, in contrast to the case of supply-side technologies, disincentives associated with rate-making and with other economic factors have been inhibiting aggressive pursuit of cost-effective demand-side programs since the 1970s, it would only be logical for an incentive program of this nature to confine itself to demand-side efficiency. In addition, EPA projects that a program that authorizes distribution of the Reserve to supply-side as well as demand-side programs may risk depleting the Reserve after approval of only a very few applications. In that case, the program would be of benefit to only a few utilities, defeating its implicit purpose of promoting demand-side management and the adoption of

income-neutral ratemaking on a widespread basis.

e. *Qualified renewable energy generation.* Section 404(f)(1)(B) and § 404(f)(4) of the Act require EPA to identify and list "qualified renewable energy." The Act defines "qualified renewable energy" as electricity generation derived from biomass, solar, geothermal, or wind resources. The definition that EPA is proposing (§ 73.3 of the regulations) simply elaborates on this statutory definition.

The Act provides general criteria concerning the technologies qualifying for allowances from the Reserve. Based on these criteria, the proposal lists qualifying renewable energy sources in appendix B of part 73, subpart F. The list does not include renewable energy sources that generate electricity indirectly. As in the case of qualifying energy conservation measures, EPA also proposes to allow the qualified renewable energy generation list to be expanded by developing technologies.

In connection with the listed technologies, further elaboration in at least two areas is necessary: (i) The treatment of renewable/fossil hybrid generation; and (ii) appropriate categories of biomass.

(1) Renewable/fossil hybrids. Some renewable energy technologies function well in concert with conventional fossil fuel. The most notable example is the Luz solar thermal design, which uses natural gas to maintain steam temperatures and pressures in cases of intermittent cloud cover or early morning/late afternoon reductions in solar insolation during some months of the year. Deployment of other hybrid technologies, including biomass/coal co-firing and wind/combustion turbine combinations, is likely in the near future.

The Act does not provide specific guidance on how the EPA should treat generation from these hybrid technologies in terms of calculating allowances. EPA decided that allowance calculations should be based on renewable resource heat input. In practice this means, for example, that a solar thermal electric facility using the sun for 75% of its generation in a calendar year would receive allowances based on 75% of its total generation. This option also permits a coal plant using 20% biomass in its boiler to receive allowances for 20% of the generation from that plant.

The benefits of this option are that it reflects actual reliance on renewable resources and associated emissions reductions, thus reducing the risks of an over-allocation, or spurious allocation, of potentially scarce allowances in the Reserve to any one applicant. At the same time, it provides an incentive to maximize use of renewable resources vis a vis fossil resources. Although this option requires EPA to collect more detailed information on annual plant operations (§ 73.82(a)(9) of the regulations), it is unlikely to pose a problem, either technically or administratively.

(2) Appropriate biomass categories. Biomass, as defined by the Public Utility Regulatory Policies Act of 1978 would include (1) wood and wood waste; (2) herbaceous crops and agricultural waste; (3) landfill gas; and (4) municipal solid waste (MSW). EPA proposes to allow (1), (2), (3), and (4) be considered as biomass resources for purposes of the Reserve.

f. *Ownership criteria.* Section 404(f)(2)(B)(v) of the Act requires that recipients of allowances from the Reserve must own or operate at least one affected unit. EPA is proposing that partial ownership or cooperative operation agreements pursuant to the guidelines set forth under "life-of-the-unit, firm power contractual arrangement(s)," as defined in § 402(27) of the Act, meet the eligibility requirements. EPA proposes to require that the applicant list the name and Allowance Tracking System number of at least one affected unit for which the applicant is listed as an owner or operator.

g. *Demonstration that requirements have been met.* Section 404(f)(2)(D) of the Act requires that each applicant demonstrate that:

(1) It is paying in whole or in part for the energy conservation measures deployed or the renewable energy generated;

(2) Avoided emissions are quantified in accordance with the regulations promulgated under section 404(f) of the Act;

(3) It has implemented a least cost plan;

(4) The qualified energy conservation measures or renewable energy in question are consistent with the least cost plan;

(5) The least cost plan has been approved by the State regulatory authority or another entity with rate-making authority;

(6) In the case of conservation measures, the state rate-making authority has established rates that ensure net income neutrality as certified by DOE; and

(7) It owns or operates at least one affected unit.

EPA proposes several additional requirements for qualifying applications. First, EPA proposes to require the applicant to state and certify the amount of money spent on conservation or renewable energy generation. This information is being required simply to substantiate that the utility has met the statutory payment requirement. Second, quantification of avoided emissions will be determined by the following calculations, as prescribed in section 404(f)(2)(E) of the Act:

For Conservation: [(kWh saved) * (.004) divided by (2000)]

For Renewable Energy:

[(kWh generated) * (.004) divided by (2000)]

Where .004 = (.4 lbs/mmBtu) × (10,000 Btu/kWh) and 2000 lbs = 1 ton = 1 allowance

These calculations reflect a hypothetical coal plant that emits .4 pounds of sulfur dioxide per million Btu of coal burned. Based on these calculations, the 300,000 Conservation and Renewable Energy Reserve allowances will be allocated to reflect 150,000 million kWh of "saved" or renewable energy generation.

For the least cost plan requirement, EPA proposes that the State regulatory authority or entity with rate-making authority certify that the applicant has, and is implementing, a least cost plan. EPA believes a certification is sufficient demonstration because least cost plans undergo public review and comment.

3. Application Procedures

The Conservation and Renewable Energy Reserve is structured to encourage utilities and their regulators to move forward with least-cost planning and regulatory reform. Such actions will not only facilitate compliance with the Act, but could be critical elements in economically and environmentally sound utility long-term planning (House Report No. 490, 101st Cong., 2nd sess., at 675 (1990)).

Although the Act does not prescribe procedures for allocating allowances from the Reserve or for implementing the program, today's proposal includes specific provisions governing the allocation of the allowances, first-come, first-served rules, procedures for verifying conservation program effectiveness and renewable energy generation, and certification of the application.

a. *Application and allocation.* There are a variety of options for distributing allowances from the Reserve within the guidelines specified in the Act. Options considered by EPA include:

(1) Reserving allowances for later allocation based on planned conservation and/or renewable energy generation;

(2) Allocating allowances based on planned conservation and/or renewable energy generation; and

(3) Allocating allowances only after demonstration of achieved conservation and/or renewable energy generation.

EPA is proposing that allowances be awarded annually based on installed measures or renewable generation that occurred during the previous calendar year. Verification is to be provided at the time of application, and applications are to be submitted after measures have been installed and verification has been made. EPA decided that reserving or allocating allowances based on planned conservation measures or renewable energy generation would jeopardize the integrity of the Reserve. Though these methods provide some certainty of allowance availability for utilities planning to implement conservation measures or invest in renewable energy generation, they make the Reserve vulnerable to the possibility of miscalculated avoided emissions or conservation measures or renewable energy projects never being implemented. As a result, the "true" number of allowances in the Reserve would not be certain, which could discourage participation in this program. Allocation of allowances after energy savings have been verified is simple and direct, and will encourage early and aggressive action by utilities to implement conservation measures or utilize renewable energy.

EPA is proposing that applications be submitted to the Administrator beginning on January 1, 1993, which is one year following the beginning of the period of applicability. Commenters have suggested that EPA delay this date by a few months to allow time for more accurate verification of conservation savings. They argue that since the allowances from the Reserve are allocated on a first-come, first-served basis, there will be pressure to send in applications to the Administrator before complete and accurate verification of conservation savings can be fully assured. EPA believes, however, that the likelihood that the Administrator would reject deficient applications should minimize this problem. EPA requests specific comments on the annual date on which applications for the Reserve may be submitted.

The burden of expediting the verification process, described below, will be on the applicant utility. This means that applications for allowances from the Reserve may be submitted annually or less frequently for a number of years for retrospective energy savings. Allowances will not be distributed for savings to be realized in future years, even for measures already installed.

EPA examination of currently "eligible" utilities—that is, those with active conservation programs and/or renewable generation, least cost plans, and net income neutrality for conservation measures—indicates that if allowances are allocated annually on a retrospective basis the depletion of the Reserve is unlikely until at least a few years into the program. Thus, the recommended option extends the incentive effects of the program by allowing several years during which other utilities may initiate conservation and renewable energy programs. In addition, under the proposal, application and verification will occur at the same time, thus eliminating the risk that EPA will be forced to reallocate already-allocated allowances whenever verification reveals that previously approved programs have not been implemented successfully.

Commenters have indicated that these proposed procedures might preclude *de facto* any allowances from being awarded to renewable energy generation, since longer periods of time elapse between planning and deployment of new renewable energy capacity. To prevent this outcome, EPA is proposing that the Administrator review the allocations from the Reserve when 240,000 allowances have been allocated. If at that time either renewable energy generation or conservation projects appear to be in a position of receiving fewer than 60,000 allowances before the Reserve is depleted, an amount equal to 60,000 allowances less any allowances already allocated for either renewable energy or conservation will be placed in a subaccount in the Reserve and allocated only for conservation or renewable energy projects, depending on which type has not yet received 60,000 allowances.

The proposed 60,000 allowance subaccount for renewable energy is consistent with the CAAA legislative history that tried to encourage development of renewable energy projects. The Senate version of the Amendments included a provision for a Renewable Energy Reserve, not dissimilar from the renewable energy component of the program ultimately incorporated in the Act. Specific rationale for a renewable energy program was provided by Senator Wyche Fowler during the Senate debate on the Amendments.

> * * * As we deliberate on how to get the cleanest air in the most cost-effective manner, we must not overlook the potential of conservation and renewable energy technologies that are inherently clean. Renewable energy sources such as solar, wind, and geothermal are emissions free. This amendment will bring these and other renewable sources on line to lay a foundation for better air quality * * *
> (Senator Wyche Fowler, Congressional Record—Senate, S 3777, April 3, 1990.)

EPA determined that 60,000 allowances was an appropriate number to "guarantee" for renewable energy generation. EPA examined the potential for different renewable resources to be on-line during the eight years of Reserve operation and concluded that a 60,000-allowance "floor" would be adequate to assure "later-starting" renewable energy projects participation in the Reserve program.

Finally, EPA proposes to limit the total number of allowances that may be allocated in connection with any one of the four categories of renewable resources—biomass, solar, geothermal, and wind—to no more than 10% of the Reserve, or 30,000 allowances. This reflects EPA's concern that biomass, which, in the aggregate, represents more than 90% of the combustible MSW stream, could absorb a disproportionate share of the Reserve.

EPA estimates that waste-to-energy generation alone could consume in excess of 100,000 allowances from the Reserve. The number and geographical diversity of waste-to-energy facilities in operation, or commissioned to operate in the near future, suggests that, relative to other sources of renewable energy generation, MSW is a renewable resource already being substantially exploited. The widespread and growing utilization of these facilities appears to reflect strict regulation, under the Resource Conservation and Recovery Act, of sanitary landfills, which, in turn, favors the MSW-incineration alternative. In addition, waste-to-energy facilities, by definition, provide a major function—waste disposal—beyond the production of energy that other renewable energy resources do not. In view of the incentive-creating function of the Reserve, EPA concluded that it would be inappropriate to devote up to one-third of the Reserve to a technology already in widespread and increasing use.

At the same time, however, a significant component of the combustible MSW stream is biomass. Accordingly, EPA does not believe a complete exclusion of these resources to be justifiable, particularly in view of the proposed limit on allocations for electrical generation from any one category.

The 30,000-allowance limit in conjunction with the 60,000-allowance minimum discussed above, ensures that at least 30,000 allowances will be available for renewable resources currently utilized less than MSW in waste-to-energy facilities.

b. *First-come, first-served.* To implement the Act's requirement that allowances be allocated on a "first-come, first-served basis," EPA proposes to determine the order in which applications are received by their date and time stamp. EPA believes that all applications to this program will not be submitted concurrently. Instead they are likely to be submitted gradually as applications are completed. As a result, a more complicated queuing system is unnecessary.

EPA proposes to conditionally approve applications and designate allowances from the Reserve pending DOE certification of net income neutrality. Final approval will be granted upon notification of certification by DOE. In the event that the number of allowances remaining is smaller than the amount for which a qualifying applicant has applied, the applicant will receive the number of allowances remaining in the Reserve.

For the certification of net income neutrality by DOE, the Secretary of DOE will also process and certify Supplement A of the application according to the order, by date and time, in which it is received from either the applicant, or by the Administrator in the case of Supplement A submitted to the EPA and then forwarded to the Secretary.

c. *Verification.* The Act requires the utility to quantify its estimates of avoided emissions according to regulations promulgated by the Administrator (§ 404(f)(2)(B)(ii)). Given the complexity and multitude of verification methods in quantification of energy conservation savings and the degree to which State regulators are, and will continue to be, involved in conservation program evaluation, the guidelines must be flexible enough to allow State innovation, but rigorous enough to provide EPA with the tools necessary to ensure that the Reserve is allocated appropriately, particularly in cases of non-State-regulated utilities in which verification responsibility falls directly to EPA.

Quantifying emissions avoided from renewable energy generation is not nearly as difficult as verifying conservation savings, given the formula specified in the Act (Kwh * .004 divided by 2000). Utility record-keeping will provide EPA with the necessary renewable generation figures to verify that avoided emissions are calculated correctly.

(1) State/utility experience with estimating conservation savings. During the past decade a number of utilities have gained experience in demand side program implementation. Nonetheless, evaluation of program effectiveness remains imprecise. Because many factors affect energy consumption—weather, economic conditions, household size and age of occupants, age of appliances, etc.—it is difficult to isolate energy saved as a result of conservation efforts.

(2) Recommended guidelines. In view of State experience of conservation program evaluation, EPA proposes to defer to State regulators for conservation verification in cases where the State has regulatory oversight. Regulatory scrutiny in these cases is likely to be fairly rigorous as necessitated by net income neutrality ratemaking structures, which are also required for qualification. In cases of non-State-regulated utilities, EPA will require the use of its conservation verification protocol (described below), which will be published at a later date.

(3) EPA conservation verification protocol. The EPA Conservation Verification Protocol will likely include, standard methodologies and procedures for use by applying utilities and/or their independent contractors in developing estimates of energy saved as a result of implemented conservation programs. The Protocol is currently under development and will be published for public comment under a separate **Federal Register** notification.

d. *Application submittal.* Applications for allowances from the Reserve must be signed by a "certifying official" (as defined in section 73.3 of the regulations) of the utility. Subject to application approval and allowance availability, the utility will be allocated allowances from the Reserve. If the utility does not have an account in the Allowance Tracking System, the utility must complete and send to EPA a New Account/New Authorized Account Representative Form either with the Reserve Application or after the application has been approved. The application may, but is not required to, be submitted by a "designated representative" as specified in Subpart B of part 72, because the Reserve allowances are being allocated to utility systems for conservation or renewable energy and not to individual units. However, the recipient of the Reserve allowances may transfer the allowances to a unit account if he or she desires.

e. *Certification.* All applications must be certified by the certifying official as to the truth and correctness of the information submitted to EPA. The Act requires that utilities regulated by State regulatory authorities must submit their applications to their State regulatory authority for review of accuracy and compliance with the requirements of the Act and the regulations as proposed herein. EPA proposes to require, in the application, a signed certification by a State regulatory authority that this review was completed.

VI. Continuous Emission Monitoring Regulation

A. Rule Background and Summary

1. Applicability

Pursuant to section 412 of the Clean Air Act Amendments of 1990 (the Act), proposed part 75 of the Acid Rain program applies to existing affected units, to each unit that elects to become an affected unit, and to each new utility unit upon commencement of its operation. Emission monitoring equipment required by the proposed rule would be installed, operational, and certified by November 15, 1993, for Phase I affected units; by January 1, 1995, for existing Phase II affected units; and upon commencement of operation for new units. An affected unit that formally commits to retirement before December 31, 1994, would be exempt from the requirements of the proposed rule.

2. Purpose of the Continuous Emission Monitoring Program

Continuous emission monitoring systems (CEMS) are indispensable to the successful implementation of the Acid Rain program because of two unique characteristics that distinguish this program from traditional emission limitation programs. First, the compliance flexibility provided by the allowance trading provisions of the sulfur dioxide (SO_2) control program mandates complete and accurate reporting of emissions data by the affected units. Second, the Act expresses the program's emission goals in terms of absolute tons of SO_2 and nitrogen oxides (NO_x). (Traditionally, such goals have been expressed in terms of pollutant mass emission rates relative to the heat input of the fuel which, for utilities, have been in pounds of pollutant per million British thermal units (lbs/mmBtu).)

The CEMS program proposed in today's rule is essential to the proper functioning of the allowance trading provisions of the Acid Rain program because the Act uses the newly created "commodities" of allowances as proxies

for emissions in the trading. As noted previously, allowances may be freely bought and sold, and EPA will compare each unit's allowances held against the unit's SO_2 emissions reported for each year. Therefore, if continuous emission monitoring fails to provide an accurate, timely, impartial, and comprehensive estimate of SO_2 emissions, the value of allowances will be unstable and uncertain, and the confidence of market participants in the trading program will be undermined.

EPA's review of other markets, including environmental emission trading markets, reinforces this conclusion. The U.S. General Accounting Office's 1986 Study of EPA's regulations for Lead Rights Banking noted that the self-reported, but unverified and uncertified, data on lead emissions from refineries produced numerous inaccuracies, which resulted in possible overstatements of both the emission reductions and the number of lead rights that were created.[24] A similar outcome for the Acid Rain program would frustrate the emission reduction goals of the Act and undermine the value of emission control investments.

Numerous other markets reviewed by the Agency, including various stock markets, futures exchanges, and commodity markets, illustrate that there is a fundamental, essential feature to smoothly operating markets: A method for certifying the existence and quantity of the commodity to be traded.[25] Most often, certification of the commodities are made by independent institutions whose integrity and reputation are such that their certification is trusted. The CEMS program proposed today incorporates that feature by requiring the regular reporting of emission data certified to be accurate. Additionally, regular verification and certification of the accuracy of the CEMS data by sources is reinforced by EPA's independent audit authority.

Title IV of the Act makes clear that its purpose is to "reduce the adverse effects of acid deposition through reductions in annual emissions of sulfur dioxide of ten million tons from 1980 emission levels, and, in combination with other provisions of this Act, of nitrogen oxides emissions of approximately two million tons from 1980 emission levels * * *." (Section 401(b)). In addition, section 403(a)(1) requires that in Phase II of the program the Administrator "shall not allocate annual allowances to emit sulfur dioxide pursuant to section 405 in such an amount as would result in total annual emissions of sulfur dioxide from utility units in excess of 8.90 million tons * * *." EPA believes that a comprehensive monitoring program, as mandated in section 412 of the Act, is fundamental to ensuring that the acid deposition precursor emission reduction goals of the Act are, in fact, achieved.

3. Statutory Authority

The primary statutory authority for the regulations proposed in part 75 is contained in section 412 of the Act, which requires the installation and operation of a continuous emission monitoring system (CEMS) on each affected unit and the quality assurance of data for SO_2, NO_x, opacity, and volumetric flow. In addition, section 821 of the Act requires all affected units in the Acid Rain program to monitor carbon dioxide (CO_2) emissions.

Section 402(7) of title IV of the Act defines a CEMS as "* * * the equipment as required by section 412, used to sample, analyze, measure, and provide on a continuous basis a permanent record of emissions and flow (expressed in pounds per million British thermal units [lbs/mmBtu], pounds per hour (lbs/hr) or such other form as the Administrator may prescribe by regulations under section 412)".

Section 412(d) requires that if data from the CEMS or from an alternative monitoring system approved by the Administrator (equivalent to a CEMS) are not available for a unit during any period of a calendar year and, as provided in section 412(d), "the owner or operator cannot provide information, satisfactory to the Administrator, on emissions during that period, the Administrator shall deem the unit to be operating in an uncontrolled manner * * *." The subsection also requires EPA to prescribe a means in the Acid Rain CEMS regulations for calculating emissions during missing data periods.

In accordance with section 412(a), EPA must promulgate the specifications and quality assurance requirements for CEMS, recordkeeping and reporting requirements, and criteria for approval of alternative monitoring systems not later than eighteen months after enactment (i.e., by May 15, 1992). An alternative system must be "demonstrated as providing information with the same precision, reliability, accessibility, and timeliness as that provided by CEMS * * *. Such regulations may include limitations on the use of alternative compliance methods by units equipped with an alternative monitoring system as may be necessary to preserve the orderly functioning of the allowance system, and which will ensure the emissions reductions contemplated by this title."

Section 821 of the Act provides that all affected sources subject to title IV[26] also be required to monitor CO_2 emissions according to the same timetable as in section 412 (b) and (c), and report the data to the Administrator. These provisions are to be applied in the same manner and extent as the requirements for emission monitoring data reporting under section 412. There is no explicit requirement in section 821, however, to use CEMS to monitor CO_2 emissions. Using the reported data, the Agency is required to compute each affected unit's aggregate annual total CO_2 emissions, compile these data into a computerized database, and make the aggregate annual CO_2 emissions data available to the public.

4. Summary of Today's Proposed Rule

Under the proposed rule, the owner(s) and operator(s) of an affected unit (or units) would be required to install and operate a CEMS on each affected unit unless otherwise specified in the regulation. The CEMS is defined as including the following components: (1) An SO_2 pollutant concentration monitor, (2) a NO_x pollutant concentration monitor, (3) a volumetric flow monitor, (4) an opacity monitor, (5) a diluent gas monitor, and (6) a data acquisition and handling system (usually computer-based) for recording and performing calculations with the data.

Table 1, CEMS Components Required in Proposed Acid Rain program Monitoring Regulation, arrays the components of a CEMS that would be required for the monitoring of each specific pollutant parameter (i.e., SO_2, NO_x, volumetric flow, diluent gas, and opacity). The CEMS components that would be used for CO_2 are also listed, although, as mentioned previously, the Act does not mandate the continuous emission monitoring of CO_2. In all cases, a data acquisition and handling system is necessary to record, perform calculations on, and report the emission data. Table 1 also lists the units of

[24] Report to the Chairman, Subcommittee on Oversight and Investigations, Committee on Energy and Commerce, House of Representatives, "Vehicle Emissions: EPA Program to Assist Leaded-Gasoline Producers Needs Prompt Improvement," GAO/RCED-86-182.

[25] "Fostering a Spot Market for Allowances: Institutional Parallels in Other Markets," A. McGartland, draft discussion paper prepared for U.S. EPA, 1991.

[26] The statute cites title V and section (Sec.) 511 in Sec. 821. However, as there is no section 511 in the law, the citations are clearly typographical errors, reflecting the title and section references for earlier versions of the legislation (see e.g., H.R. 3030, Rept. 101-490, May 17, 1990). The logically correct citations are to title IV and section 412.

measure proposed for each pollutant parameter.

TABLE 1.—CEMS COMPONENTS REQUIRED IN PROPOSED ACID RAIN MONITORING REGULATION

Acid rain monitoring requirement (units required)	Required CEMS monitoring component					
	SO_2	NO_x	Flow	Opacity	Diluent gas	Data handling
SO_2 (lbs/hr)	yes		yes			yes.
NO_x (lbs/mmBtu)[1]		yes			yes	yes.
Opacity (%)				yes		yes.
CO_2 (lbs/day)[2]			yes		yes	yes.

[1] Heat input in mmBtu/hr is also required.
[2] Alternative methods may be used to monitor CO2.

Measurements of SO_2 concentration would be combined with measurements of volumetric gas flow (exhausting from the unit or emitted as a byproduct of an industrial process) to obtain estimates of SO_2 mass emissions per unit time (in lbs/hr), as required by the Act. Flow monitors always measure gas flow rate on an actual or "wet" basis. Some SO_2 pollutant concentration monitors, however, measure SO_2 concentration on a "dry" basis (meaning that the moisture of the gas has been removed). The measurements used to calculate SO_2 emissions in lbs/hr would be on the same moisture basis. Accordingly, units that employ "dry" SO_2 pollutant concentration monitors would correct their gas flow rate measurements for moisture. Under the proposed rule, EPA would allow sources to use a variety of moisture determination methods, including standard saturation/temperature tables and continuous moisture monitors, provided the corrected flow rate measurements satisfy the performance standards for monitor certification.

Similarly, measurements of NO_x concentration would be combined with measurements of a diluent gas, either oxygen (O_2) or CO_2, exhausting from the unit to obtain the estimates of the NO_x emission rate relative to the heat input of the fuel (in lbs/mmBtu). Accordingly, the proposed rule would define a NO_x CEMS as the combination of a NO_x pollutant concentration monitor and a diluent gas monitor.

The proposed rule requires a continuous opacity monitoring system (COMS) to monitor the obscuration caused by particulate matter in the gas emission stream. Gas-fired units combusting no less than 90 percent natural gas with oil as the back-up fuel would be exempted from this opacity monitoring requirement, since these units individually, and as a group, emit very little particulate matter.

The proposed rule also exempts units employing a flue-gas desulfurization (FGD) system from the opacity monitoring requirement. Most units affected by the Acid Rain program are already required by other regulations to install and utilize a COMS; the exemption proposed here would not exempt these units from such requirements. Data from all COMS shall be sent to the applicable permitting agency.

Units that monitor CO_2 continuously would need a CO_2 diluent monitor plus a flow monitor to estimate CO_2 emissions which are to be aggregated into daily totals for reporting. The proposed rule would not require units to continuously monitor CO_2 emissions. Units that generate CO_2 emissions only by combustion would be allowed to calculate, using specified methods and procedures, CO_2 mass emissions (in lbs/day) based on the measured carbon content of the fuel and the amount of fuel combusted. Units that also generate CO_2 emissions by means other than fuel combustion—for example, by flue-gas desulfurization (FGD) using wet limestone scrubbing—would be required either to monitor emissions or to calculate the total amount of CO_2 generated by combustion and by the FGD process using procedures in appendix E of the proposed rule.

Under the proposed rule, each monitor in the CEMS and the system as a whole would be required to be installed, and its performance verified and certified by the Administrator, before it can be used in the Acid Rain program.

The following performance certification tests would be required for continuous emission monitoring systems: (1) A calibration error test for each pollutant concentration monitor, diluent gas monitor, and those flow monitors for which an approved test has been developed; (2) an electronic stability test for each flow monitor that does not conduct a daily calibration error test; (3) relative accuracy and bias tests for the SO_2 pollutant concentration monitor, the flow monitor, and the NO_x emission monitoring system; (4) a cycle response time test for the SO_2 pollutant concentration monitor and the NO_x emission monitoring system; and (5) an orientation sensitivity test and an interference test for differential pressure flow monitors only. No later than January 1, 2000, relative accuracy and bias tests would be added for the combined SO_2/flow emission monitoring system (pollutant concentration monitor and flow monitor). For continuous opacity monitoring systems, performance certification tests for calibration error, response time, zero drift, and calibration drift would be conducted according to the requirements in 40 CFR part 60, appendix B.

To certify a CEMS, the designated representative for the owner(s) and operator(s) of an affected unit would submit a request to the Administrator, who would issue a notice approving or disapproving the request. Such requests would include the following information: unit identification (including type of monitoring, emission control, and back-up monitoring systems, if any), stack diameter and height, the date and results of each performance certification test, supporting documentation to substantiate the test results, and documentation to verify that the computerized data acquisition and handling system properly calculates and converts the recorded emission data.

If the proposed system is disapproved, the owner(s) and operator(s) would need to make revisions in the equipment, procedures or methods as applicable, and resubmit a request for certification.

For each system, the proposed rule requires the development and implementation of a written quality assurance/quality control plan, which would be submitted with the affected unit's Acid Rain permit application. Daily performance checks of the monitoring equipment, including gas calibration error tests and visual and electronic inspections, would be required to be included in the plan by

the proposed rule. Daily calibration error tests for flow monitors are not required,[27] but the rule would enable sources to reduce the frequency of required relative accuracy testing for flow monitors by conducting daily calibration error tests. Flow monitors that do not conduct calibration error tests would instead conduct daily electronic stability tests. In addition to these daily tests, periodic relative accuracy test audits and bias tests would be required for the SO_2 pollutant concentration monitor, the flow monitor, and the NO_x emission monitoring system. A three-point calibration error test would also be required quarterly for all pollutant concentration and diluent monitors.

The mathematical construction of the relative accuracy statistic makes it more difficult for pollutant concentration monitors and emission monitoring systems on low-emitting units to pass these tests. Therefore, the proposed rule provides an optional (less stringent) alternative for units emitting less than 250 parts-per-million, by volume (ppmv) SO_2.

No alternative monitoring system is proposed in today's regulation as a preapproved system equivalent to a CEMS on the required statutory criteria of precision, reliability, accessibility, and timeliness. However, EPA is proposing an exception to the SO_2 continuous emission monitoring requirements for oil-fired and gas-fired units due to the relative homogeneity of the sulfur content distribution in these fuels, the close approximation to CEMS goals achievable by the available monitoring methods for these fuels, and the minimal impact of SO_2 emissions from units in these categories. These units would be required to use prescribed methods of in-line oil flow metering and oil sampling and analysis for sulfur content in order to estimate pounds of SO_2 emitted per hour when oil is being combusted. The prescribed excepted monitoring methods for SO_2 emissions closely approximate the performance of a CEMS. These units are not, however, exempted from the NO_x continuous emission monitoring requirements under part 75.

In order to receive approval to use an alternative monitoring system in lieu of a CEMS or a component of a CEMS (e.g., SO_2 pollutant concentration monitor or flow monitor), the affected unit would be required to submit statistical evidence and other data demonstrating that the proposed alternative would provide information equivalent or superior to a CEMS. Under the proposed rule, EPA would use the performance of certified SO_2 pollutant concentration monitors, flow monitors, and NO_x emission monitoring systems as benchmarks for approving or rejecting proposals for alternative monitoring systems. Today's rule specifies procedures, analyses, and supporting documentation that would be required for demonstrating the equivalency of alternative monitoring systems to CEMS on the required criteria of precision, reliability, accessibility, and timeliness.

Affected units that are granted Phase I extensions under 40 CFR part 72 and use qualifying Phase I technology (i.e., a technology that achieves at least a 90-percent SO_2 removal efficiency) would have to employ additional monitoring. The proposed rule requires that each such unit be equipped with an SO_2 pollutant concentration monitor and a diluent monitor for measuring SO_2 emissions at the inlet and outlet of the control device. Provisions are included in the proposed rule for demonstrating achievement of the required 90-percent reduction in SO_2 emissions through qualifying Phase I technology, on an annual basis, from the date of start-up testing of the emission control device through 1999.

Consistent with section 412(a) of the Act, the proposed rule would allow the owner(s) and operator(s) of two or more affected units that utilize a common stack to install one SO_2 emission monitoring system. Where Phase I and Phase II affected units utilize a common stack, the owner(s) and operator(s) would be required to: (1) Install a separate CEMS in each duct leading to the stack; (2) install separate CEMS in the common stack and in the ducts for each Phase II unit and calculate the Phase I unit emissions as the difference between the common-stack value and the sum of the Phase II unit values; (3) install a CEMS in the common stack and differentiate the individual unit emissions parametrically, or (4) declare the Phase II unit as a substitution unit in accordance with the requirements of part 72. Where an affected unit and a nonaffected unit share a common stack, the proposed rule would provide these same options to the owner(s) and operator(s), except, in Option (4), the owner(s) and operator(s) would declare the nonaffected unit as a opt-in unit in accordance with the requirements of part 74. If the continuous emission monitoring system is installed such that any portion of the flue gases from an affected unit can by-pass the monitoring system, a separate CEMS would be required on the by-pass flue gas stream.

Likewise, the owner(s) and operator(s) would be allowed to monitor for combined NO_x emissions in a common stack under certain conditions. If two or more units subject to the same NO_x emission limitation under parts 72 and 76 share a common stack, they may monitor for NO_x emissions in the common stack. If two or more units with different NO_x emission limitations under parts 72 and 76 emit through a common stack, they may either: (1) Monitor for NO_x emissions for each affected unit; (2) monitor the common stack for NO_x emissions and use the most stringent NO_x emission limitation of any unit sharing the stack; or (3) monitor the common stack for NO_x emissions and submit a NO_x emissions averaging plan. If units with a NO_x emission limitation and units without a NO_x emission limitation share a common stack, they would differentiate the NO_x emissions at each unit.

All continuous emission monitoring systems would be required to be in continuous operation and to be capable of sampling, analyzing, and recording at least every 15 minutes. All emissions and flow data would be reduced to one-hour averages. Four data points would comprise a valid hour. During maintenance, repair, calibration or other required quality assurance activity periods, however, two or more data points would be allowed to comprise a valid hour. Failure of the system to acquire the required data points would result in the loss of data for the entire hour. In this event, the owner(s) and operator(s) would be required to use the prescribed procedures for calculating emissions for the missing data periods.

The proposed rule contains procedures for compiling "information satisfactory to the Administrator" for substituting data where no valid data have been recorded for the SO_2 pollutant concentration monitor, the flow monitor, or the NO_x CEMS (consisting of the NO_x pollutant concentration monitor and the diluent gas monitor). For the SO_2 and flow monitors, where valid data have not been recorded for either monitor, the missing data procedure would apply to each monitor individually. For the NO_x CEMS, if either monitor is without a valid hour of recorded data, the data for both monitors would be deemed invalid, and substitute data would be provided for both monitors using the prescribed missing data procedures. Such information establishes preapproved information satisfactory to the Administrator. The proposed approach

[27] Except for ultrasonic monitors, which are required to perform a daily zero-and-span check. This check is essentially a calibration error test.

establishes the methods that may be used to "fill in" missing data, following the general principle that the longer the gap in the recorded data and/or the lower the annual monitor availability, the more conservative the value to be substituted. (Annual monitor "availability" refers to the number of total hours of valid data capture per year, expressed as a percentage of total unit operating hours.) For SO_2 concentration missing data, these substitute values are either an average of the values recorded in the hour preceding and the hour following the missing data occurrence, or the 90th-percentile value recorded during a preceding period of some prescribed length. During certain specified periods each of these statistics is calculated, with the higher of the two being used. In each case, the data acquisition system would relate the sulfur (ppm) emission rate to the sulfur content in the coal consumed for selection of the appropriate value. The procedure proposed for NO_x emission rate data and flow data is similar in structure, but allows missing data replacements to be calculated based on correlation with load.

Table 2 summarizes the proposed missing data procedures for SO_2 concentration data. First, if annual monitor availability is greater than or equal to 95 percent and the duration of the missing data period is 24 hours or less, the substituted value for each such hour would be the average of the hourly values recorded for the hour immediately before and the hour immediately following the missing data period. If the missing data period is longer than 24 hours, the substituted value for each hour would be the 90th-percentile of the hourly values, for the relevant sulfur content range, recorded by the monitor in the last 30 days, or the average of the hourly values recorded for the hour immediately before and the hour immediately following the missing data period, whichever is higher.

TABLE 2.—Summary of CEMS Substitution Criteria for Estimating Values for Missing Data Periods

[SO_2 Concentration Data][1]

Annual availability (percent) of monitor or system	Number of hours missing (N)	Value substituted for each missing hour
Greater than or equal to 95%	N ≤24 hours	Average of the hour recorded before missing data period and the hour recorded after missing data period.
	N >24 hours	90th-percentile[2] over 30 days, or average of hour before and hour after, whichever is higher.
Less than 95% but greater than or equal to 90%.	N ≤6 hours	Average of the hour recorded before missing data period and the hour recorded after missing data period.
	N >6 and ≤24 hours	90th-percentile[2] over 30 days, or average of hour before and hour after, whichever is higher.
	N >24 hours	90th-percentile[2] over 365 days, or average of hour before and hour after, whichever is higher.
Less than 90%	N >0 hours	90th-percentile[2] over 365 days, or average of hour before and hour after, whichever is higher.

[1] The procedure used for NO_x emission rate and flow data is similar in structure, but allows missing data replacements to be calculated based on correlation with load.

[2] I.e., 90th-percentile hourly value for the relevant sulfur content range associated with the missing data period.

The second group of procedures applies when annual monitor availability is less than 95 percent, but greater than or equal to 90 percent. A three-tiered system is proposed for this group where each tier is related to the length of the missing data period. If the missing data period is six hours or less, the substituted data value for each hour would be the average of the hour immediately before and the hour immediately after the missing data period. If the missing data period is greater than six hours but less than or equal to 24 hours, the substituted value for each hour is the 90th-percentile of the hourly values, for the relevant sulfur content range, recorded by the monitor in the last 30 days, or the average of the hourly values recorded for the hour immediately before and the hour immediately following the missing data period, whichever is higher. If the period is longer than 24 hours, the substituted value for each hour is the 90th-percentile of the hourly values, for the relevant sulfur content range, recorded by the monitor in the last 365 days, or the average of the hourly values recorded for the hour immediately before and the hour immediately following the missing data period, whichever is higher.

When annual SO_2 concentration monitor availability is less than 90 percent, the substituted data value for each hour of missing data would be the 90th-percentile of the hourly values, for the relevant sulfur content range, recorded by the monitor in the last 365 days, or the average of the hourly values recorded for the hour immediately before and the hour immediately following the missing data period, whichever is higher.

As mentioned previously, the procedure proposed for filling in missing NO_x emission rate data and flow data is similar in structure to the SO_2 missing data procedure, but allows missing data replacements to be calculated based on correlation with load, rather than fuel sulfur content.

The proposed rule also contains procedures to be used for converting the hourly emissions data for SO_2 into pounds per hour (lbs/hr) and for NO_x into pounds per million British thermal units (lbs/mmBtu). Procedures also are provided for calculating hourly emission rates of CO_2 when it is monitored continuously and for estimating daily CO_2 emissions when a monitor is not used. The rule also contains prescribed American Society for Testing and Materials (ASTM) methods, procedures, and equations for excepted monitoring methods based on oil sampling and analysis available to gas-fired and oil-fired units.

The proposed rule includes requirements for notification, recordkeeping, and reporting for the Acid Rain program. The requirements include monitoring plans to be submitted as part of the compliance plan and permitting process stipulated by part 72; written notifications of monitor certification tests; daily recording of hourly emissions and flow data and other information; maintaining records of emissions and flow data, other measurements, and system maintenance; initial and quarterly reports of quality assurance and quality control tests for the continuous emission monitoring systems; and reports of

recorded emissions, flow, unit operating status, and monitoring performance data. The proposed rule would require the owner(s) and operator(s) to electronically report the required information on a quarterly basis as an ASCII flat file via either an IBM-compatible personal computer floppy diskette or a modem.

The proposed part 75 monitoring regulations do not specify a procedure for administrative appeal of determinations made by the Administrator under part 75 (cf. 40 CFR part 72, subpart H). However, EPA is considering adopting such a procedure for challenges to the monitor certification requests of this Part. EPA requests comment on whether monitor certification or other specific determinations should be covered by an Administrative appeal procedure. Comments should also address whether an appeal should be permitted only for the monitoring plan as a whole, rather than for the individual determinations that underlie or are included in the monitoring plan. In addition, EPA requests comment on whether the appeal procedure set forth in support of part 72 (the Acid Rain Permitting Regulations) should be used as the appeal procedure for part 75 as well.

B. CEMS Description and Background

A continuous emission monitoring system (CEMS) is a system that measures, on a continuous basis, the amount of pollutants emitted into the atmosphere in exhaust gases from combustion processes or as the byproduct of manufacturing or other industrial processes. When used in its broadest sense, CEMS can also refer (as it does in Title IV) to the continuous opacity monitoring of obscuration caused by particulate matter and the monitoring of other gases such as CO_2.

Prior to 1978, EPA used CEMS for electric utilities only as an indicator that plant operators were performing proper operation and maintenance of air pollution control equipment. In 1978, with the promulgation of the New Source Performance Standards (NSPS) for fossil fuel-fired steam generators, 40 CFR part 60, subpart Da (subpart Da), CEMS data were used, for the first time, to assess affected sources' compliance by comparing CEMS-measured concentrations of SO_2 and NO_x in exhaust stack gases with applicable emissions standards.

In developing today's proposed CEMS regulation for the Acid Rain program, EPA began with a review of the existing subpart Da monitoring requirements to evaluate their applicability to the goals of title IV. Subpart Da represents a natural starting point for the development of the Acid Rain CEMS regulation since it has become the standard reference for all subsequent federal and State CEMS regulations. The electric utility industry now looks to the CEMS provisions in subpart Da for quality assuring their CEMS devices, whether monitoring new or existing sources, and uses them to shape their internal quality assurance programs. Also, using Subpart Da as an initial template for the Acid Rain CEMS regulation and performance standards would reduce the need to replace existing CEMS systems that have been performing reliably and accurately with new systems. Representatives from utilities, State agencies, and environmental groups, as well as members of the Acid Rain Advisory Committee (ARAC), have endorsed the approach of using Subpart Da as the initial template for the proposed regulation.

Pivotal to this review and analysis, however, was the recognition by EPA that: (1) The market-based approach of Title IV differs significantly from the traditional control approach embodied in subpart Da; (2) CEMS technology has improved markedly—particularly in the areas of monitor reliability, expected data capture rates, and accuracy of emissions measurements—since the promulgation of subpart Da; and (3) incentives to promote further CEMS improvements, producing higher data capture rates and more accurate emissions measurements as the Acid Rain program matures, could be essential to maintaining confidence in the viability of the allowance trading market as a means of achieving cost-effective environmental regulation.

Moreover, the goals and monitoring objectives of the Acid Rain program are different from those of subpart Da. A fundamental difference is the Acid Rain program's need for 100 percent accounting of all SO_2 mass emissions (in tons) from affected units each year for comparison with the allowances they hold. This contrasts with the subpart Da approach of relating SO_2 concentrations to an emissions standard expressed in terms of pollutant mass emitted relative to the heat input of the fuel (in lbs/mmBtu). The requirement for 100 percent accounting of SO_2 emissions leads to a key difference between the monitoring objectives of subpart Da and the Acid Rain program. Title IV of the Act requires affected units "to sample, analyze, measure, and provide on a continuous basis a permanent record of emissions and flow[.]" Another difference is the need for timely, accurate, and consistent measurements of SO_2 and NO_x emissions to support the allowance trading and the NO_x averaging components of the Acid Rain program.

Subpart Da requires affected sources to install and continuously operate SO_2 and NO_x concentration monitors to measure concentrations in the exhaust gas, and diluent gas monitors to measure the concentration of a major gaseous constituent, O_2 or CO_2, in the gaseous pollutant mixture exhausting from the unit, which is needed to convert the ppmv pollutant concentration measures into units of the subpart Da emissions standard (lbs/mmBtu). Additionally, subpart Da requires affected sources to install and operate continuous opacity monitors for measuring the opacity of gases emitted into the atmosphere.

In addition to these subpart Da requirements, section 402(7) of the Act stipulates that the Acid Rain program measure flow continuously. This has prompted EPA to expand the definition of CEMS. Under subpart Da the gas-concentration monitors, together with a (usually computer-based) data acquisition and handling system for recording and performing calculations with the measured pollutant data, comprise a continuous emission monitoring system (CEMS). For the purposes of the Acid Rain program, the rule would define CEMS to include flow monitors, which continuously measure the volumetric flow of gas through a stack or duct. In conjunction with concentration monitors, the flow monitors will permit continuous measurement of SO_2 mass emissions per unit time (in lbs/hr).

Notwithstanding the recognized differences between the program goals and monitoring objectives of subpart Da and the Acid Rain program, EPA's review has indicated that not only are many of the CEMS performance requirements, certifying tests, and quality assurance procedures of subpart Da applicable to the Acid Rain program with minor modification, but also the historical record of subpart Da monitors establishes a baseline for defining achievable performance for today's CEMS technology. As an example, in preparation for this proposal, both EPA and the Utility Air Regulatory Group (UARG)[28] conducted independent statistical analyses of annual monitor availabilities [29] reported for SO_2, NO_x,

[28] UARG is a group of representatives of several electric utility companies which analyzes Clean Air Act implementation issues and makes recommendations on their resolution.

[29] Annual monitor "availability" refers to the expected number of total hours of valid data

Continued

and opacity monitors at units subject to subpart Da requirements, in order to assess the likely performance that could be achieved by well-maintained systems based on current technology.[30] Both studies have produced essentially identical results: the average annual availability during 1988–1990 of subpart Da pollutant concentration monitors, either SO_2 or NO_x, was above 95 percent and the average annual availability of subpart Da opacity monitors was above 97 percent.

Similarly, both EPA and UARG analyzed monitor relative accuracy [31] values that have been submitted in periodic data assessment reports (required under subpart Da quality assurance procedures) during 1988 and 1989 to assess the likely performance that could be achieved by SO_2 and NO_x pollutant concentration monitors based on current technology.[32] The EPA analysis of this data demonstrates a feature of the subpart Da relative accuracy statistic that limits its usefulness in assessing accuracy. While the subpart Da relative accuracy statistic ensures that all sources of monitor error (both random and non-random) do not exceed a stipulated percentage of the average reference method measurements, it does not detect consistently low CEMS measurements, i.e., low bias.[33]

capture per year, expressed as a percentage of total unit operating hours.

[30] E7–EPA AIRS CEM Subset Analysis, January 17, 1991, and Technical Note by Roberson Pitts, Inc., Assessing Data Availability at Units Subject to Subpart Da New Source Performance Standards, September 1990.

[31] "Accuracy" refers to the difference between the emissions measurements made by a pollutant concentration monitor or a CEMS and the true values of emissions. Since the true values of emissions are unknown, CEM reference method results are assumed to represent true emissions. "Relative accuracy" is a statistic commonly used to describe the systematic error (bias) and random error (imprecision) associated with data from a pollutant concentration monitor. It may also be used to describe the emissions measurement accuracy of the CEMS as a whole, as discussed later under NO_x continuous emission monitoring systems.

[32] "Accuracy and Reliability of CEMS at subpart Da (Electric Utility) Facilities," Entropy Environmentalists, Inc., March 1990, and Presentation Materials, ARAC Emissions Monitoring Subcommittee Minutes, prepared by R. Roberson for UARG, February 20, 1991.

[33] The Subpart Da relative accuracy statistic cannot detect either low or high bias. As discussed in the next section, only low bias is of regulatory concern to the Acid Rain program, since sources will find it in their economic interest to correct high bias, and only low bias theatens the emission reduction goals of the program. Therefore, the remainder of this discussion is in terms of low bias only.

Consequently, monitors with statistically significant bias can still achieve "acceptable" relative accuracy. That is, monitors that show a statistical consistency in measuring low relative to reference method results could nevertheless pass a relative accuracy test under subpart Da. Indeed, as is discussed in more detail in section C on SO_2 monitoring below, EPA data on existing monitors show that in a significant number of cases where the subpart Da relative accuracy test was passed, a bias test would have been failed had one been applied.

Recognizing the importance of accurate emissions measurements, EPA considered replacing or supplementing the relative accuracy statistic with separate statistical indicators of bias and precision. One approach considered uses the automated measurement methods recently adopted by the International Standards Organization (ISO) for determining SO_2 pollutant concentrations in emissions from stationary sources.[34] Other possible approaches include the t-statistic, rank sign, and randomness tests, which are generally regarded as appropriate statistical methods for detecting the presence of bias in experimental or instrumental data.

In order to investigate fully the potential advantages and possible shortcomings of these statistics, EPA has developed a computerized database of the individual data points (runs) from relative accuracy test audits (RATAs) of SO_2 and NO_x pollutant concentration monitors at 21 coal-fired units. This database contains over 1000 data points from SO_2 pollutant concentration monitor RATAs as well as information on the applicable reference method (wet chemistry or instrumental), type of monitor (extractive or in situ), and measurement basis (wet or dry). The database also contains analogous RATA data for NO_x pollution concentration monitors and flow monitors.

Statistical analyses performed on this database indicate that a t-statistic test (also called a "t-test") for detecting the presence of bias would effectively identify monitors that measure consistently low or high relative to the reference method. The proposed rule would incorporate a t-test, applied to low bias only, in addition to the relative accuracy test for certifying monitors. Satisfactory monitor performance in both tests would be assessed using a 95-percent confidence coefficient, as is

[34] Standard ISO/D1S 7935, September 1990, cited in "Accuracy and Precision of CEM Systems," J. Jahnke, January 1991.

employed in the relative accuracy test required under subpart Da.

C. SO_2 Pollutant Concentration Monitoring

As discussed previously, EPA has relied upon the historical operating experience of SO_2 pollutant concentration monitors at units subject to subpart Da requirements to develop proposals for: (1) Design of the monitoring protocol, including sampling frequency and the basic time period for emissions accounting; (2) performance specification parameters for certifying monitors, including relative accuracy, bias, calibration error, and cycle time/response time; and (3) quality assurance and quality control procedures, including daily calibration checks and periodic relative accuracy test audits, bias tests, and three-point calibration error tests. Where the provisions of subpart Da continue to define adequately the capabilities of today's SO_2 pollutant concentration monitors, EPA proposes to use them for the Acid Rain program, provided they are consistent with the program's goals and monitoring objectives. Where the provisions of subpart Da no longer reflect the performance achievable with current technology or are inconsistent with the goals or monitoring objectives of the Acid Rain program, EPA is proposing different requirements.

1. System Design Considerations

a. Time Period for Emissions Accounting. Under subpart Da, an hour is the basic time unit for the accounting of emissions. This time period is consistent with the statutory language of the Act, which lists pounds-per-hour as one appropriate unit for expressing emission quantity. It was the consensus of the Acid Rain Advisory Committee [12] that, because title IV of the Act requires a continuous record of emissions, an hour is an appropriate unit. EPA therefore proposes today that an hour be the basic building block in accounting for SO_2 emissions under the Acid Rain program.

b. Sampling Frequency. The general provisions of NSPS (40 CFR part 60) specify that each component of a CEMS shall be capable of taking measurements every 15 minutes (four sampling or data points per hour) or more frequently. subpart Da of 40 CFR part 60, however, permits the use of hourly emissions data for compliance purposes if the monitor captures at least two (out of the four)

[35] Docket A–90–39, II.B.27, E–28—Emission Monitoring Subcommittee Minutes, March 20–22, 1991.

data points (§§ 60.47(a) and 60.47(b)). The intent of this provision, as described in the subpart Da preamble (44 FR 33581, June 11, 1979), was to accommodate those instruments that cannot obtain four equally spaced points during calibration periods.

To ensure that the hourly SO_2 concentration averages are as accurate as possible under the Acid Rain program, there was a strong inclination to require four data points in all hours for the hourly calculation to be valid. However, the desirability of such a requirement is limited by EPA's need under the Acid Rain program to require daily calibration checks of the SO_2 pollutant concentration monitor. EPA believes that the proposed daily calibration checks, combined with routine maintenance, are essential to ensure that the instrument is not "wavering" over time and producing erroneous measurements, and to quality assure the recorded SO_2 concentration data on a daily basis. The daily calibration checks required by subpart Da, which are less rigorous than those in today's proposed rule, typically cause the monitor to be off-line, and "unavailable" for emissions measurements, for a half-hour to an hour.[36] If EPA were to require four data points for a valid measure of average hourly SO_2 concentration in all hours, at least an hour's worth of emissions data would be lost each day from otherwise acceptable monitors during the required calibration period.

EPA is proposing to continue the practice of allowing the calculation of average hourly SO_2 concentration using two data points, each representing a 15-minute period, of the normally required four (or more) data points during hours when calibration error tests or other quality assurance activities specifically required by part 75 are being performed. During ARAC discussions, industry representatives have suggested that repair and maintenance periods, as well as periods of routine or preventative maintenance, should also be included as periods for which 2 data points are acceptable.[37] EPA agrees with this view, and is proposing to accept two data points per hour during all documented periods of calibration, quality assurance activities, repair, and maintenance.

[36] Most operators schedule these checks to "bridge" a clock hour, so the monitor is available to sample and measure two data points in the hour before the check and two data points in the hour following the check, thus losing no hours of emissions data.

[37] E14—Acid Rain Advisory Committee (ARAC) Emissions Monitoring Subcommittee Minutes, February 20, 1991.

2. Performance Specifications for Certification

EPA proposes to require the certification of each SO_2 pollutant concentration monitor, as is done under subpart Da, before that monitor may be used to satisfy any of the continuous emission monitoring requirements under the proposed rule. This certification process would involve a series of tests to verify that the monitor's performance meets or exceeds EPA's minimum performance specifications with respect to: (1) Relative accuracy of emissions measurements, (2) absence of statistically significant bias in emissions measurements, (3) calibration error over the expected range of SO_2 concentrations, and (4) cycle time/response time to alternating (high and low) SO_2 concentrations.

The primary intent of pollutant concentration monitor certification tests under subpart Da is to screen out malfunctioning systems. These tests must also fulfill a different and more demanding objective under the Acid Rain program with its allowance trading market—namely, to ensure the accurate and consistent measurement of emissions across the entire range of expected SO_2 concentrations. Accordingly, while EPA is proposing to adopt the basic tenets of subpart Da for the Acid Rain program's monitor certification process, some changes are being introduced to improve the accuracy of emissions data.

a. *Relative Accuracy.* EPA has traditionally used the relative accuracy statistic, discussed previously, to evaluate the accuracy by which a pollutant concentration monitor samples, measures, and analyzes pollutants in the exhaust gases emitted by a combustion process or as a byproduct of an industrial process. EPA has defined a series of reference methods for determining specific pollutant concentrations in a gaseous pollutant mixture that are defined as the true values of the pollutant concentration. The relative accuracy performance specification tests for SO_2 concentration would consist of a minimum of nine sets of paired comparisons between monitor measurements and contemporaneous reference method measurements of flue gas SO_2 concentration in parts per million by volume (ppmv). Under subpart Da the comparison of paired sets of monitor measurements and contemporaneous reference method measurements of pollutant concentrations in the gas is used to provide an independent assessment of monitor accuracy under actual operating conditions. Hence, reference method test results are assumed to be equivalent to, or a proxy for, the true values of the pollutant concentrations. EPA has defined four reference methods for evaluating the accuracy of SO_2 pollutant concentration monitors.[38] Most units subject to subpart Da requirements currently use either Method 6 (wet chemistry) or Method 6C (instrumental).

Subpart Da established a relative accuracy of 20 percent as the standard for defining acceptable monitor performance with respect to the accuracy of emissions measurements. Both the EPA and UARG analyses [39] of the relative accuracies reported by SO_2 pollutant concentration monitors at units subject to subpart Da requirements indicate that over 90 percent of these monitors routinely perform better than the 20-percent standard. All the monitors performing below this standard are located at "low-emitting" units, defined as units emitting at the rates of 0.5 lb SO_2/mmBtu or less. With the exception of these low-emitting units, all subpart Da monitors routinely perform better than the 20–percent standard.

Subpart Da provides low-emitting units with the option of using an alternative (less stringent) standard. EPA considered proposing a similar exception for low emitters at ± 10 percent of the mean difference between the reference and CEMS values. However, this approach would not completely avoid the problem that as the emissions get small enough the percentage increases disproportionately to the significance of the difference in emission rate. This is because the ratio, like the relative accuracy statistic, tends to produce a large relative percentage error for low-emitting units since its denominator is the mean of the emissions values determined by reference method tests, which will be a small number for low emitters. EPA believes that an absolute limitation provides the most appropriate protection for low-emitting sources, and accordingly proposes a limitation of ± 15 percent ppmv. This approach appropriately affords the lowest-emitting units the most latitude, and EPA's analysis of its database indicates that approximately 90 percent of

[38] 40 CFR part 60, appendix A, methods 6, 6A, 6B, and 6C.

[39] "Accuracy and Reliability of CEMS at subpart Da (Electric Utility) Facilities," Entropy Environmentalists, Inc., March 1990, and Presentation Materials, ARAC Emissions Monitoring Subcommittee Minutes, prepared by R. Roberson for UARG, February 20, 1991.

existing sources are currently within this limit.

Because of the importance of accurate emissions measurements to the allowance trading market, EPA is proposing a relative accuracy of 10 percent as the standard for defining acceptable SO_2 pollutant concentration monitor performance under the Acid Rain program. EPA believes that this relative accuracy standard more closely reflects the performance that can be achieved by well-maintained monitors based on current technology than does subpart Da's 20-percent standard. Analyses on EPA's database of SO_2 pollutant concentration RATA data indicate that over 89 percent of the RATAs conducted during 1987–1990 at non-low-emitting units subject to subpart Da requirements produced relative accuracies of 10 percent or less on a ppmv basis.[40]

Like subpart Da, today's proposal includes a less-stringent alternative standard for low-emitting units. The proposed alternative standard would apply to units emitting at the rates of 250 ppmv (approximately equivalent to 0.5 lb SO_2/mmBtu) or less. It would require that the average difference between the monitor measurements and the values determined by the reference method tests be no greater than 15 ppmv.

b. *Bias.* As mentioned previously, the relative accuracy statistic of combines statistical descriptors of bias and precision in a manner that allows monitors with statistically significant bias (measuring consistently low or high relative to the reference method) to achieve "acceptable" relative accuracy. The existence of statistically significant low bias would lead to understated emissions, thereby threatening the achievement of the emission reduction goals of the Act as well as the market's confidence in the link between allowances and actual emissions. Therefore, a method to detect and eliminate such bias is proposed as part of the Acid Rain monitoring program.

As discussed below, in today's proposal EPA would require sources to test for bias using relative accuracy test audit (RATA) data. EPA considered whether it would be possible to ascertain the presence of bias using data from the daily calibration error tests, rather than RATA data. In EPA's judgment, the proposed RATA-based procedure has the added benefit of being an independent check of the monitor under actual operating conditions. The RATA relies on the reference method as a second, separate means of detection. This approach provides a check of the entire system and is likely to detect any problems which may develop either in the stack or along the sampling train and data system. Thus, potential sources of bias experienced only under actual operating conditions are detected by this approach, a judgment confirmed by a professional engineering study [41] and discussions with industry experts. Based on these considerations, EPA believes that a RATA-type test, which employs a reference method independent of the CEMS, provides the best basis for detecting bias. As discussed below, EPA requests comment on the merits of this approach.

EPA has evaluated the probable incidence of bias in otherwise acceptable monitors using its computerized database of SO_2 pollutant concentration RATA data from units subject to Subpart Da requirements.[42] EPA has employed four types of statistical tests to assess monitor bias: (1) The ISO (International Standards Organization) test which combines a t-test with both a bias threshold defined on the span of measurement and an upper limit on the CEMS variance; (2) a t-test that does not incorporate either the ISO's bias threshold or its limit on CEMS variance; (3) a nonparametric [43] rank sign test; and (4) a nonparametric randomness test.

EPA has rejected the nonparametric test options for certifying monitors because experience indicates that the SO_2 pollutant concentration RATA data approximate a normal distribution. With normally distributed data, the two nonparametric statistical tests would be more likely to yield erroneous results than either the ISO or the t-test for bias. Furthermore, the ISO and t-test have been shown to yield reliable results even when data are only approximately normally distributed. They also can provide information about the level of confidence associated with a particular result. The "level of confidence" refers to the degree of uncertainty associated with the acceptance or rejection of the hypothesis being tested. For example, if a monitor fails a bias test at the 95-percent level of confidence, the probability is only five percent that this monitor was incorrectly rejected—i.e., that the monitor was not actually measuring either consistently low or consistently high relative to the reference method. Subpart Da uses the 95-percent confidence coefficient in all its statistical tests for certifying monitors and quality assuring CEMS data.

The ISO test is an attractive option because of its credibility internationally. This method uses a t-test procedure to detect monitor bias and, at the same time, establishes a limit on the allowable variance of the CEMS. In setting limits on the variance of the CEMS, however, the ISO test appears to be too demanding for current U.S. CEMS technology: Less than 30 percent of the SO_2 RATAs in EPA's database from units subject to subpart Da requirements would pass this bias test at the 95-percent level of confidence.

Of the available tests, in EPA's judgment the t-test at the 95-percent level of confidence is the most satisfactory method for screening out biased monitors since, like the ISO method, it takes advantage of the normal data distribution to provide a less error-prone test than either of the nonparametric approaches, and yet does not present too stringent a threshold for current U.S. CEMS technology. The test would be applied to detect low bias only, since only low bias threatens the emission reduction goals of the Act, and in any case it will be in the economic interest of sources to detect and correct high bias. EPA believes that the t-test, at a 95-percent level of confidence, applied to low bias only, provides a standard that can be achieved by well-maintained SO_2 pollutant concentration monitors based on current technology. Seventy percent of the SO_2 RATAs in EPA's database passed this test even though the monitors were not required to meet any type of bias performance specification. Moreover, since a substantial number of RATAs in EPA's database were performed as long ago as 1986–1988, it can be assumed that subsequent improvements in monitor technology will yield even better performance on the bias test.

In today's proposal, EPA would require the t-test at the 95-percent level of confidence, applied to low bias only,[44] using the same data as that used

[40] Study by The Cadmus Group, W. Warren-Hicks, August 14, 1991.

[41] "Stationary Source Emissions—Determination of the Mass Concentration of Sulfur Dioxide—Performance Characteristics of Automated Measuring Methods," pp. 11–12, Technical Committee 146, International Standard 7935, International Standards Organization, The Hague, The Netherlands, 1989.

[42] Technical Notes, Kilkelly Environmental Associates, W. Warren-Hicks, dated April 25, 1991 and May 23, 1991.

[43] "Nonparametric" means that the test is appropriate for data that may not conform to the normal (bell-shaped) distribution.

[44] Considering only low-biased results as failures in the t-test at the 95-percent level of confidence is statistically equivalent to employing a one-tailed t-test with an alpha value of 0.025. Thus, in Table 8–1 in appendix A of the regulations, the appropriate t-values are denoted by $t_{0.025}$.

to certify relative accuracy, as the certification test for SO_2 concentration monitor bias. The recorded SO_2 concentration data from a monitor that fails a bias test would not be considered invalid, or "missing," but would be adjusted upward to compensate for the bias using the method shown in appendix A of the rule. Monitors failing the bias test would be certified by incorporating the aforementioned data adjustment factor, which would be applied to all data recorded between the time of the failed bias test and the time of the next successful bias test. Sources would have the option of continuing to apply the bias-adjustment factor to their monitor readings or eliminating the source of the bias. The bias adjustment factor would be applied to all monitor readings until a new RATA is conducted in which the relative accuracy standard is met and the bias test is passed. In the new RATA, if the unit passes the relative accuracy test but again fails the bias test, the bias adjustment factor would be recomputed based on the new RATA values and this new factor would be applied to subsequent monitor readings.

EPA has relied on the relative accuracy test as a key element of its subpart Da requirements. The test has a number of advantages: it is an already-accepted part of several of EPA's other regulatory programs, it is well-understood by the regulated community, and passage of the test has been demonstrated as achievable by most existing units. However, as noted earlier, the relative accuracy test represents a combination of a measure of monitor bias and of the random variance in CEMS measurements (relative to the reference method), and it has been suggested that there may be supplemental tests (e.g., t-test, rank sign test) that would be more effective in assuring measurements that are sufficiently accurate to meet annual emission reduction requirements and support allowance trading. In addition, some have argued that there is measurement error associated with the reference method (as well as with the CEMS) and that because of this error the relative accuracy and bias tests could result in incorrect conclusions on the inaccuracy or bias of the CEMS. As a result, EPA is interested in further comments with respect to the following concerns that have been raised with regard to today's proposal:

- What characteristics (for example, in terms of measurement error) are necessary to ensure compliance with the annual emission targets set under the Clean Air Act?
- Given the proposed requirement that units conduct a daily calibration test, how effective is the relative accuracy test in assuring a sufficiently accurate measurement of annual emissions? Similarly, how effective is the bias test in meeting this objective?
- Are there alternative ways of structuring the relative accuracy and bias tests that would be as effective, or more effective, and less costly in assuring measurements sufficiently accurate to meet annual emission requirements and support allowance trading?
- Are there cases where, given other quality data checks (and the resulting confidence in the data), an exemption from the bias test could be warranted and still have the monitoring data necessary to assure achievement of the emission-reduction goals and support allowance trading? For example, it has been suggested that a relative accuracy threshold be set below which no bias test would be required, i.e., a relative accuracy of 5 percent, 3 percent, or 2.5 percent. Also suggested was a threshold for the mean difference between the reference method and the CEMS (expressed as a percentage deviation of the arithmetic mean of the CEMS measurements from the arithmetic mean of the reference method measurements) below which no bias test would be required, i.e., at a mean difference of 5 percent or 2.5 percent.

These questions apply to bias testing for flow and NO_x monitors, covered in sections VI.D.2 and VI.E.2, respectively, as well as for SO_2 monitors, covered in this Section. EPA requests comment on these questions with respect to any or all of these pollutants.

c. *Calibration error.* EPA is proposing to expand Subpart Da's two-point (low and high) calibration error test for monitor certification into a three-point (low, mid-range, and high) test under the Acid Rain program to ensure the accuracy of SO_2 emissions measurements throughout the entire range of expected values. A calibration error test "challenges" the monitor under controlled conditions with gases of known pollutant concentrations in order to evaluate the closeness of its emissions measurements to different certified concentration levels of the calibration gases. As outlined below in Section 3 on quality assurance and quality control procedures, the gases used to supply the known concentrations are required to be either standard reference material or Protocol 1 gases certified to be within 2 percent of the corresponding standard reference material.

For calibration error tests under Subpart Da, the high level of the pollutant concentration is normally between 1.25 and 2 times the applicable emissions standard and the low level is normally zero. Under Subpart Da, accuracy in measuring SO_2 emissions is necessary only to the extent of determining whether or not the unit's emissions exceed the applicable emission rate standard. Once the emissions are shown to exceed the applicable standard, however, the accuracy of the monitor's measurements are no longer important. Moreover, subpart Da constrains units to operate within a narrow range of SO_2 concentrations, so monitor accuracy over a wide concentration range is not a concern.

Under the Acid Rain program with its allowance trading market, however, units can operate over a potentially wide range of SO_2 concentrations. Some units are expected to emit SO_2 concentrations at substantially higher levels than those experienced under Subpart Da. Under the Acid Rain program, SO_2 emissions must be measured accurately throughout the entire range of expected SO_2 concentrations. The proposed rule would require calibration error tests at three levels, defined as a percentage of the expected range of SO_2 concentrations, as follows: (1) 0–20 percent for the low level, (2) 40–60 percent for the mid-range level, and (3) 80–100 percent for the high level. The "high" level of SO_2 concentration used for calibration error tests under Subpart Da would probably correspond, for many units, to the "mid-range" level under the Acid Rain program.

EPA proposes to use subpart Da's performance specification of 2.5 percent for calibration error for monitor certification under the Acid Rain program. That is, to qualify for certification, a monitor's measurements of SO_2 concentrations would be required to not deviate from the known calibration gas values by more than 2.5 percent for each of three concentration (low, mid-range, and high) levels.

d. *Cycle time/Response time.* EPA proposes to use the cycle time/response time test required for monitor certification under subpart Da for the Acid Rain program. The objective of this test is to determine how quickly the monitor responds to changes in pollutant concentration. The cycle time/response time test "challenges" the monitor with alternating gases of known (high and low) pollutant concentrations and records the amount of time required for the monitor to register 95 percent of

the difference between the two concentration values. EPA proposes to use Subpart Da's performance specification of 15 minutes as the maximum time allowed.

3. Quality Assurance and Quality Control Procedures

As in the case of the performance specifications for the certification of SO_2 monitors, EPA has relied on subpart Da's procedures for quality assurance (QA) and quality control (QC) of monitor accuracy and recorded emissions data as the initial template for defining these requirements under the Acid Rain program. Subpart Da QA/QC procedures are specified in Appendix F, 40 CFR part 60. They consist of a series of tests to be performed periodically (daily, quarterly, semi-annually, and annually) to ensure that the monitors, once certified, continue to operate reliably and accurately. Also included in subpart Da are specifications for maintaining records of QA/QC test dates, descriptions, and results and for the submission of quarterly Data Assessment Reports to EPA and other applicable regulatory authorities.

Under subpart Da, quality assurance procedures are needed to assess an affected unit's compliance with applicable emissions standards on a 30-day rolling average basis. The Acid Rain program, however, will require a more timely assessment of the accuracy of recorded emissions data for the proper functioning of the allowance trading market. Timely and accurate emissions data will help foster certainty in the market, thus facilitating trades, whereas unknown or inaccurate emissions data could lead to the hoarding of allowances as a compliance "cushion." Thus, EPA is proposing to require affected units to quality assure each day's recorded emissions data within 24 hours. Also, as was done with the performance specifications for the certification of monitors, EPA is proposing other changes to subpart Da's QA/QC procedures to improve the accuracy of emissions measurements.

a. *Daily calibration error test.* As mentioned previously, EPA is proposing to expand Subpart Da's daily calibration drift checks for the SO_2 pollutant concentration monitor into daily two-point (low and high concentration) calibration error tests so as to quality assure the recorded emissions data on a daily basis. Under the Acid Rain program, affected units would be required to use either Protocol 1 gases or gases that are traceable to either a standard reference material gas or a National Institute of Standards and Technology (NIST)/EPA-approved certified reference material gas for these daily calibration error tests, in addition to the quarterly calibration error tests, as required under Subpart Da. The accuracy of emissions measurements is directly related to the quality of gases used in the calibration error tests. Previous studies have shown that the "known" SO_2 concentration in some commercially available test gases may deviate from the specified value by as much as 18 percent, which is not acceptable quality.[45]

"Standard reference material gases" are gases of known pollutant concentration that are certified and distributed by the National Institute for Standards and Technology. These gases are of the highest quality, but are available only in limited quantities. "Protocol 1 gases" are manufactured according to a standard protocol that uses samples of standard reference material gases and compares the pollutant concentration in the Protocol 1 gas against its benchmark in the standard reference material gas.

Recent audits of Protocol 1 gases indicate that their pollutant concentrations are within five percent of standard reference material benchmark in over 90 percent of the gases tested.[46] EPA was concerned that this level of quality control would not be sufficient for the Acid Rain program, and therefore conducted an examination of the current quality of the Protocol 1 calibration gases sold on the market today. This examination showed that, for 90 percent of the samples, the pollutant concentrations were within 2 percent of the concentration of standard reference materials, constituting a marked improvement in the quality over previous figures.[47] Given the results of the aforementioned EPA survey and the fact that the accuracy of Protocol 1 gases is directly related to the accuracy of the CEMS, the proposed regulation would require that all calibration gases used in the Acid Rain program be vendor-certified to be within 2 percent of the indicated value, as measured against the standard reference material benchmark. Protocol 1 gases would be audited annually and the results published.

Field personnel from EPA Regional Offices have observed that most units already use Protocol 1 gases for daily calibration drift checks of their SO_2 pollutant concentration monitors. Consequently, the requirement to use Protocol 1 gases daily should not increase the burden on the regulated community. This assessment has been confirmed by members of the ARAC Emissions Monitoring Subcommittee, who recommended that EPA require the use of Protocol 1 gases for daily calibration error tests under the Acid Rain program.[48]

A concern was raised by a few electric utilities that employ a certain type of in situ monitor which has a built-in gas reference cell for calibration drift checks. For this type of monitor, it would be cumbersome to perform daily calibration error tests using Protocol 1 gases. However, these monitor models were initially fabricated over 10 years ago; many units have already replaced them with newer models that are amenable to daily calibration error tests using Protocol 1 gases. EPA expects that the remainder of these monitors may be replaced in the reasonably near future. Therefore, EPA solicits comment as to whether such an exception would be warranted, the conditions of any such exception, and whether the quality, stability and reliability of the calibration gas in the built-in cells of these monitors would satisfy the Protocol 1 criteria.

Subpart Da has two complementary standards for defining unacceptable monitor performance with respect to daily calibration drift error: (1) Drift exceeds four times the performance specification of 2.5 percent in a given day, and (2) drift exceeds twice the specification for each of five consecutive days. A monitor is considered "out of control" if it fails the daily calibration error test on the basis of either of these standards. The recorded emissions data from such a monitor would be considered invalid for compliance purposes.

EPA believes that the calibration error standards under Subpart Da are neither sufficiently stringent to ensure the accuracy of emissions measurements nor reflective of today's CEMS technology achievements. Accordingly, EPA proposes to adopt the calibration error standard used in the Commonwealth of Pennsylvania's CEMS regulations for the Acid Rain program—namely, drift should not exceed 5 percent (twice the specification

[45] "Performance Audits of EPA Protocol Gases and Inspection and Maintenance of Calibration Gases," R. Wright, E. Tew, C. Decker, D. von Lehmden, and W. Barnard, Journal of the Air Pollution Control Association (JAPCA), Vol. 37, No. 4, April 1987.

[46] "Accuracy Assessment of EPA Protocol Gases in 1988," R. Wright, C. Wall, C. Decker, and D. von Lehmden, JAPCA Notebook, Vol. 39, No. 9, September 1989.

[47] Draft 1991 audit results, memorandum to EPA, R. Shares, Research Triangle Institute, August 13, 1991.

[48] E14—Acid Rain Advisory Committee (ARAC) Emissions Monitoring Subcommittee Minutes, February 20, 1991.

of 2.5 percent) in a given day. The recorded emissions data from a monitor that fails this calibration error standard would be considered invalid, or "missing," prospectively until monitor drift is brought under control (within specification).

b. *Periodic performance tests.* As discussed earlier, the Acid Rain program requires emissions data which is both more comprehensive and more accurate than that required under subpart Da. The most important factor in obtaining such data is accurate and reliable monitoring. EPA proposes to assure this enhanced accuracy and reliability by requiring monitor performance testing that is more frequent and comprehensive than the tests in subpart Da. Specifically, EPA proposes to require three kinds of performance tests on SO_2 concentration monitors—a relative accuracy test audit, a bias test, and a three-point calibration error test—to be run at varying intervals, depending on the type of test and the results obtained. With the exception of the bias test, the recorded SO_2 concentration data from a monitor that fails any of these tests would be considered invalid, or "missing," prospectively until corrective action is taken and the monitor achieves the required performance standard. In the case of the bias test, concentration data that fails would be adjusted to compensate for bias until the system is corrected and passes a subsequent bias test.

1. Relative Accuracy Test Audit

As discussed elsewhere in this preamble in the section on performance specifications and standards, a relative accuracy test audit, or RATA, consists of nine sets of paired comparisons between the monitor's pollutant concentration measurements and the values determined contemporaneously by a reference method. The proposed relative accuracy standard for SO_2 pollutant concentration monitors in the RATA is identical to that proposed for the monitor certification tests. That is, under the proposed rule, SO_2 pollutant concentration monitors would be required to achieve relative accuracies of 10 percent or less in the RATAs. The recorded SO_2 concentration data from a monitor that fails a RATA would be considered invalid, or "missing," prospectively until corrective action is taken and the monitor achieves the required performance standard.

EPA is proposing to require semi-annual RATAs for SO_2 pollutant concentration monitors, with one exception described below. This frequency is consistent with the practice commonly followed in the clean coal technology program, and is judged to be sufficiently frequent to assure that owner(s) and operator(s) will give proper attention to monitor maintenance while avoiding unnecessarily frequent testing. In deliberations over the achievable level of monitor performance, EPA considered the cumulative distribution of relative accuracy results for SO_2 concentration monitors in EPA's database of relative accuracy test audits (RATAs). As previously mentioned, the results indicated that 89 percent of the RATAs would have passed at the 10 percent level of relative accuracy being proposed in today's notice. Moreover, the results showed that 69 percent and 45 percent of the RATAs would pass at the 7.5 percent and 5 percent levels, respectively, even though they had been required to meet only the subpart Da threshold of 20 percent. In discussions with electric utility officials, however, it became clear that disagreement persists as to what these data show regarding the achievable level of relative accuracy over a larger universe of units. While these officials agree that relative accuracies below 10 percent are clearly achievable in some cases, they believe the evidence is insufficient to show that all installations can meet such a requirement.

At the same time, in these discussions, it became clear that both EPA and the utility representatives agree that the achievement of relative accuracies substantially better than 10 percent is an indication of especially good design, maintenance, and quality control, and that such results should permit the reduction in the frequency of subsequent testing. Given these facts, EPA is proposing a reduced RATA frequency for those monitors that achieve a relative accuracy of 7.5 percent or better.[49] These monitors would be allowed to reduce the subsequent RATA frequency from semi-annual to annual, and to retain this frequency as long as relative accuracy remains at 7.5 percent or better. This feature reflects EPA's judgment that the achievement of 7.5 percent reflects a monitor performance which allows sufficient confidence in monitor quality control to permit extending the inter-test period. Further, EPA agrees that this incentive-based approach to accuracy improvement is a sensible way to encourage advances in the monitoring program. Table 3 summarizes the required RATA frequency as a function of achieved relative accuracy.

[49] Sources meeting the 10% requirement but not achieving a relative accuracy of 7.5% or better would be allowed two tries (i.e., they could collect two sets of RATA data) to achieve 7.5%, and thereby lower their RATA frequency.

TABLE 3.—RATA FREQUENCY FOR SO_2 CONCENTRATION MONITORS

Relative accuracy	Required RATA frequency
≤10%	Semi-annual.
≤7.5%	Annual.

2. Bias Test

The periodic bias tests on SO_2 pollutant concentration monitors for the Acid Rain program would be conducted with the same frequency and at the same time as the RATAs, would employ the RATA data, and would be identical to the bias test described previously for monitor certification. The proposed performance standard for SO_2 pollutant concentration monitors in the bias test is also identical to that proposed for monitor certification. That is, under the proposed rule, SO_2 pollutant concentration monitors would be required to pass a t-test, applied to detect low bias only, at the 95-percent level of confidence. As discussed previously, the recorded SO_2 concentration data from a monitor that fails a bias test would not be considered invalid, or "missing," but would be adjusted upward to compensate for the bias, using the method shown in appendix A of the rule, until corrective action is demonstrated in a subsequent bias test. Sources would have the option of continuing to apply the bias-adjustment factor to their monitor readings or eliminating the source of the bias. The bias adjustment factor would be applied to all monitor readings until a new RATA is conducted in which the relative accuracy standard is met and the bias test is passed. In the new RATA, if the unit passes the relative accuracy test but again fails the bias test, the bias adjustment factor would be recomputed based on the new RATA values and this new factor would be applied to subsequent monitor readings.

As proposed, the bias test regulations would allow a source to re-take the bias test at any time in order to attempt to pass or reduce the size of the bias data adjustment. In discussions about bias test design, some have voiced the concern that sources saddled with a large bias adjustment factor might take advantage of natural test-to-test variability by rerunning the RATA/bias test a number of times until, by chance, they passed the test or at least achieved a lower adjustment factor. Such a procedure would be analogous to taking

a large amount of RATA data and picking out the best runs to show achievement of a relative accuracy standard. Existing procedures governing the conduct of RATAs prevent this tactic (results of multiple tries must be averaged, and consecutive runs must be used) and it has been suggested that analogous strictures are needed in the bias case. As an example of such a stricture for bias, the rule could include a requirement to use the results of all runs up to a maximum of 36 paired samples. This would improve the quality of the bias assessment as more trials were attempted.

On the other hand, EPA wants to encourage sources to "fix" biased monitors and pass the bias test, rather than simply accepting the adjustment factor. Any contemplated limitation on the number of attempts to pass must take this into consideration, since sources would have less incentive to fix biased monitors if they had to wait until the next scheduled RATA/bias test to be rid of the adjustment factor. EPA invites comment on the importance of this problem and on regulatory approaches to address it.

3. Three-Point Calibration Error Test

EPA proposes to require a quarterly three-point calibration error test on SO_2 pollution concentration monitors for the Acid Rain program. This test would be identical to the three-point calibration error test described previously for monitor certification. Under the proposed rule, a monitor's measurements of SO_2 concentrations would not be allowed to deviate from the known values by more than 5 percent for each of three concentration (low, mid-range, and high) levels. Many industry representatives indicated that this limitation was inadequate based on the variability of the quality of the calibration cylinder gas. EPA agrees with the underlying concern, but believes that the 5 percent deviation will be achievable due to the addition of the requirement for vendor certification of the calibration cylinder gas to the 2 percent level.

In developing this standard, EPA considered a requirement of 2.5 percent accuracy, identical to the certification requirement. Such a standard might be achievable, given that the most recent EPA survey found that 90 percent of sampled Protocol 1 gases were within 2 percent of the value of standard reference materials. However, EPA believes it is more reasonable to allow the calibration error to vary as much as 5 percent on quarterly assessments. Several manufacturers have indicated that this standard is readily achievable with their instruments. Furthermore, the Commonwealth of Pennsylvania requires a 3-point calibration error test with a 5 percent accuracy standard, and monitors there have had little trouble satisfying these requirements.[50]

4. Monitoring of SO_2 Reductions From Qualifying Phase I Technologies

Section 402(19) of the Act defines a "qualifying phase I technology" as "a technological system of continuous emission reduction which achieves a 90 percent reduction in emissions of sulfur dioxide from the emissions that would have resulted from the use of fuels which were not subject to treatment prior to combustion." Under subsection 404(d) of the Act, a Phase I unit equipped with a qualifying Phase I technology or transferring its emissions reduction requirement to a unit using a qualifying Phase I technology may apply for a two year extension in meeting the Phase I sulfur dioxide requirements and for extra allowances from a special reserve.[51] In order to determine if units given an extension are eligible for the Phase I extension reserve allowances, EPA must receive information to verify that the emissions reduction technology actually reduces sulfur dioxide emissions by 90 percent.

EPA is proposing both a start-up demonstration test and an annual demonstration of the sulfur dioxide removal efficiency achieved by units that are reducing sulfur dioxide emissions for the purpose of receiving a Phase I extension. The initial test would require a thirty day average of the sulfur dioxide emission rate in pounds of sulfur dioxide per million British thermal units (lb/mmBtu) at the inlet (entrance) and outlet (exit) of the emission controls, similar to the start-up performance test required for sulfur dioxide emission controls under NSPS. Both the Agency and the owner(s) and operator(s) of the unit would be able to evaluate if the emission controls were capable of achieving a 90 percent reduction of sulfur dioxide.

EPA considered whether to require this thirty-day test to apply at all times when emissions are produced by the unit. However, several electric utility representatives have pointed out that short duration malfunctions and periods of start-up and shutdown could adversely affect an average sulfur dioxide removal efficiency when the average is calculated using only 30 days' worth of data.[52] Furthermore, the Agency recognizes that there will probably be more problems and malfunctions during the first few months of operation of the emission reduction controls. Accordingly, EPA is proposing that during this initial 30-day test, calculations will not include emissions data monitored during periods of malfunctions, start-up, or shutdown.

EPA also considered measuring sulfur dioxide emissions in pounds per hour (lb/hr) at both the inlet and outlet of the emission controls. A measurement of sulfur dioxide concentration alone might not be sufficient to determine the sulfur dioxide removal efficiency of the emission controls because of the possibility of air leaks, differences in moisture content of the measured gases, or other differences between the gases at the inlet and the outlet of the controls. This can be prevented by measuring emissions in pounds per hour with a sulfur dioxide pollutant concentration monitor and a flow monitor, or by measuring emission rate in pounds per million British thermal units with a sulfur dioxide pollutant concentration monitor and a diluent monitor for oxygen or carbon dioxide. EPA considered requiring monitoring with a flow monitor and a sulfur dioxide pollutant concentration monitor at both the inlet and the outlet. This would be consistent with monitoring the pounds per hour of sulfur dioxide for comparison with allowances held. However, several utilities which intend to apply for Phase I extensions are concerned that it may be difficult to install a flow monitor at the inlet to emission controls. They have suggested that it would be easier to install a diluent monitor and a sulfur dioxide pollutant concentration monitor at both the inlet and the outlet to the emission controls for purposes of this determination.[53] EPA agrees that this would be sufficient.

The Agency is also proposing a continuing demonstration of the sulfur dioxide removal efficiency to determine which sulfur dioxide emission reduction technologies achieve a 90 percent sulfur dioxide emissions reduction on an annual basis. The continuing demonstrations would require continuous monitoring of sulfur dioxide emission rate (lb/mmBtu) at the inlet and outlet over the course of each year from start-up of the emission controls until the end of Phase I. EPA considered

[50] "Highlights of Pennsylvania's Continuous Emission Monitoring System Quality Assurance Program," S. Darling, Pennsylvania Department of Environmental Resources, presented at 1988 Joint Power Generation Conference, Philadelphia, Pa.

[51] See 40 CFR part 72, subparts D and L.

[52] Letter from Illinois Power Company, Phase I Extension Monitoring Proposal, August 23, 1991.

[53] UARG letter, August 6, 1991.

requiring an annual 30-day test, similar to the initial 30-day test, to demonstrate continuing compliance. This has the advantage of allowing the test to be repeated during the same calendar year if the emission controls failed the test, or if insufficient monitoring data were gathered. However, various electric utility representatives have indicated that since compliance with allowances held is on an annual basis, compliance with the 90 percent sulfur dioxide reduction should also be on an annual basis.[54] EPA agrees that the statutory language could be interpreted this way, and thus, is now proposing compliance on an annual average basis. Since the annual sulfur dioxide emissions must actually be reduced by 90 percent over the course of the year, emissions data from all periods of combustion would be included in the calculation, even during periods of start-up, shutdown, and malfunctions. Because the emission rates would be averaged over 365 days instead of just 30 days, there would also be little problem with individual emission control shutdowns seriously affecting the annual average.

The Act's requirement for a 90 percent sulfur dioxide reduction was designed to encourage the use of highly efficient emission control devices, such as wet limestone scrubbers. However, the wording of the definition of qualifying Phase I technologies implies that a combination of technologies could be used, such as coal washing and a dry lime scrubber. Accordingly, EPA proposes that fuel pretreatment may also be included in calculations of sulfur dioxide emission reduction for qualifying Phase I technologies.

D. Flow Monitoring

In order to meet the Act's requirement of continuous recording of volumetric flow, all affected units would be required to install and operate a flow monitor as part of their continuous emission monitoring systems for SO_2. A flow monitor continuously measures the volumetric flow rate of exhaust gas through a stack or duct (also called a "flue"). When combined with an SO_2 pollutant concentration monitor and a data acquisition and handling system, a flow monitor can provide continuous estimates of SO_2 mass emissions per unit time (in lbs/hr). Such estimates are needed to aggregate SO_2 mass emissions into tons per year for comparison against allowances held.

EPA is proposing the use of flow monitors in today's rule. The Agency and some States have documented experience in using flow monitors for continuous emission rate monitoring.[55] Further, utilities have used flow monitors for over a decade to continuously monitor the flow of air to the boiler and for related process control applications.[56] Because flow monitors have not generally been required at electric utility sources, fewer data are available to document the reliability and accuracy of flow monitors for these sources than are available for pollutant concentration monitors. However, EPA believes the data are sufficient to support the proposed flow monitoring requirements. Some ARAC participants have endorsed EPA's position that flow monitors currently represent the only proven, direct method for continuously measuring flow that would satisfy Title IV's objectives.[57] Other monitoring methods that have been suggested such as feedwater flow rate, electrical output, or steam flow rate correlations provide only indirect estimates of flue gas flow. A review of these methods indicates that none have been shown to be especially accurate or practical.[58]

The studies cited above indicate that flow monitor annual availability is comparable to pollutant concentration monitor annual availability and that plant personnel have confidence in flow monitor performance. The average annual availability of flow monitors situated in the exhaust stacks of five coal-fired utilities and three industrial plants, as reported by plant personnel, was above 95 percent during 1989–1990, and all but one of these monitors had availabilities of 95 percent or better. This informal survey included all the main types of flow monitors that are currently being used for continuous emission rate monitoring. The lowest annual availability reported was 90 percent.[59]

There are three main types of flow monitors currently being used for the continuous monitoring of flue gas flow: ultrasonic, differential pressure, and thermal. Although all flow monitors estimate the flue gas flow rate by multiplying the cross-sectional area inside the flue (stack) by the average gas velocity, each type employs a different principle to measure average gas velocity. Ultrasonic flow monitors determine average gas velocity directly by measuring the time it takes for sound bursts to travel between two transceivers, one located downstream of the other. Differential pressure flow monitors determine average gas velocity by measuring the pressure at one or more points in the flue gas stream, and using the established relationship between gas pressure, temperature, molecular weight, and velocity. Thermal flow monitors use the same established relationship to determine average gas velocity, but they measure the difference in temperature between a heated and an unheated element in the flue gas stream.

While flow monitoring is a proven technology, today's rule represents the first major air pollution control regulation to require flow monitors for the continuous monitoring of flue gas flow at electric utility sources. Accordingly, utilities in the U.S. have had limited experience in the installation, operation, and maintenance of flow monitors for this particular application, and this limited experience has led to some concern about the reliability and accuracy of flow monitors, particularly in wet stack environments (e.g., downstream of a wet scrubber). Some electric utility representatives have suggested that in lieu of requiring Phase I units to continuously monitor flow, as mandated by the Act, EPA and the electric utility industry should cooperatively establish a two-to-three year flow monitor technology evaluation/demonstration project.[60] However, EPA believes the available knowledge is sufficient to support the proposed requirement for

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[54] Letter from Illinois Power Company, Phase I Extension Monitoring Proposal, August 23, 1991.

[55] (1) "Continuous Measurement of Total Gas Flow Rate from Stationary Sources," U.S. EPA, RTP, NC, Publication EPA–650/2–75–020, February 1975; (2) "Continuous Emission Rate Monitoring Systems On-Site Inspections at Coal-Fired Power Plants," prepared by Entropy Environmentalists, Inc., for U.S., EPA, May 11, 1990; (3) Flow Monitoring, EPA Issue Paper for the Acid Rain Advisory Committee, April 1991; (4) 40 CFR part 52, appendix E, "Performance Specifications and Specification Test Procedures for Monitoring System for Effluent Stream Gas Volumetric Flow Rate"; (5) 40 CFR part 60, appendix B, "Performance Specification 6-Specifications and Test Procedures for Continuous Emission Rate Monitoring Systems in Stationary Sources"; (6) 40 CFR part 60, appendix C, "Provisions for an Alternative Method of Demonstrating Compliance with 40 CFR 60.43 for the Newton Power Station of Central Illinois Public Service Company"; and (7) regulations in State Implementation Plans (SIPs) governing the operations of municipal incinerators.

[56] "Continuous Emission Rate Monitoring Systems On-Site Inspections at Coal-Fired Power Plants," Entropy Environmentalists, Inc., May 11, 1990.

[57] Acid Rain Advisory Committee (ARAC) Emissions Monitoring Subcommittee Minutes, April 29–30, 1991.

[58] IIA–48, "Utility Boiler Parameter Monitoring for Determination of Flue Gas Flow Rates," J. Richards, February 4, 1989.

[59] E31—Flow Monitoring, EPA Issue Paper for the Acid Rain Advisory Committee (ARAC), April 1991.

[60] "Flue Gas Flow Monitoring on Electric Utility Power Plants: Technical Issues and a Suggested Technology Evaluation/Demonstration Project," R. McRanie, April 25, 1991.

flow monitors in Phase I as well as Phase II.

In addition, a recent survey of six U.S. suppliers of flow monitoring equipment indicates that they would have no difficulty, using existing production facilities, in satisfying projected demand by affected units during either Phase I or Phase II.[61]

1. System Design Considerations

a. *Time period for flow accounting.* For the same reasons described previously under SO_2 pollutant concentration monitoring, EPA has concluded that an hour is also an appropriate time period for the accounting of flue gas volumetric flow under the Acid Rain program.

b. *Sampling frequency.* The general provisions of NSPS (40 CFR part 60) specify that each component of a CEMS shall be capable of taking measurements every 15 minutes (four sampling or data points per hour) or more frequently. All three types of flow monitors currently being used to continuously monitor flue gas flow rates would satisfy this requirement. Subpart Da has no specific criteria for flow monitors.

An equivalent data capture requirement for flow would be consistent with the proposed treatment of SO_2 concentration data under the Acid Rain program, with which the flow data would be combined, and should maintain the measurement accuracy needed to ensure an accurate accounting of annual SO_2 mass emissions for comparisons against allowances held. Accordingly, EPA is proposing to require the calculation of hourly flue gas flow rate using four data points, each representing a 15-minute period, except during the hours when calibration error tests or other quality assurance activities specifically required by this Part are being performed. During these hours, only two data points are required.

2. Performance Specifications for Certification

EPA proposes to require the certification of a flow monitor before that monitor may be used to satisfy any of the continuous emission rate monitoring requirements under the proposed rule. This certification process would involve a series of tests to verify that the monitor's performance meets or exceeds EPA's minimum performance specifications with respect to: (1) Relative accuracy of flow measurements, (2) absence of statistically significant bias in flow measurements, (3) calibration error or electronic stability, (4) sensitivity of flow measurements to orientation, and (5) probable lack of interference or plugging. The relative accuracy tests would be performed at three different load levels since studies of flue gas stratification[62] indicate that the cross-sectional profiles of gas velocities can vary significantly with load.[63] The calibration error test would be conducted at two flow-velocity-equivalent signals.

The proposed specifications for flow monitors are based upon the specifications in 40 CFR part 52, appendix E, and 40 CFR part 60, appendix B, but some changes have been introduced to improve the accuracy of the flow data.

Flow monitors always measure flue gas flow rate on an actual or "wet" basis. Some SO_2 pollutant concentration monitors, however, measure SO_2 concentration on a "dry" basis, where moisture is removed from the sample gas. The SO_2 concentration and flue gas flow rate measurements used to estimate SO_2 mass emissions per unit time (in lbs/hr) must be on the same moisture basis. Accordingly, units that employ "dry" SO_2 pollutant concentration monitors would correct the flue gas flow rate measurements for moisture. There are a variety of techniques available to estimate the moisture content of the flue gas, including continuous moisture monitors, pairs of "wet" and "dry" basis diluent monitors, and standard saturation/temperature tables.[64] EPA proposes that these and other moisture determination techniques would be acceptable provided they can produce hourly averages of corrected flow rate data and the corrected flow rate measurements satisfy the proposed performance specifications for relative accuracy and bias.

a. *Relative accuracy.* Under the proposed rule, the performance specification tests for certifying flow monitors would be similar to those described previously for SO_2 pollutant concentration monitors.[65] The flow performance specification tests would consist of a minimum of nine sets of paired comparisons between monitor measurements and contemporaneous reference method measurements of flue gas flow rate in cubic feet per hour at standard conditions (scfh). Reference method test results are assumed to be equivalent to the true values of the flue gas flow. EPA has defined Reference Method 2 for evaluating the accuracy of flow monitors (40 CFR part 60, appendix A). Reference Method 2 uses velocity traverses with an S-type pitot tube, which employs the same measurement principle as differential pressure flow monitors, to determine average flue gas velocity. As mentioned previously, the proposed rule requires affected units to perform flow monitor performance specification tests at three different loads: the minimum safe operating load, the normal load, and 90-percent of full operating capacity. In cases where the normal load is within 10 percent of either the minimum or 90-percent values, a more representative mid-range-value would be chosen.

In assessing the question of the appropriate performance standard for flow monitors, EPA examined existing regulations as well as performance data on existing monitors. Appendix E of 40 CFR part 52, promulgated in 1975, established a relative accuracy standard of 10 percent for flow monitors used in connection with federally approved State air quality implementation plans. Moreover, both EPA's review of the available literature and preliminary findings from a series of on-site flow monitor evaluations indicate that a relative accuracy standard of 10 percent or less can be achieved by well-maintained flow monitors based on current technology.[66] In particular, relative accuracy test audit data from EPA-sponsored flow monitor performance evaluations under varying loads at three test sites[67] have verified the appropriateness of the 10 percent standard. Relative accuracies of five percent or less have been achieved for some runs at high (daytime) load. Two of these test sites have flow monitors installed downstream of a wet scrubber and, as such, represent "worst case" scenarios for evaluating the accuracy of flow monitor measurements.

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[61] "Flow Monitor Vendor Survey Results, Entropy Environmentalists, Inc., prepared for U.S. EPA, November 26, 1990.

[62] "Flue gas stratification" is a condition where the gas velocity at any single point varies significantly from the average gas velocity by more than 10 percent. It is more difficult to measure average gas velocity accurately when flue gas stratification occurs.

[63] "Velocity Stratification," Entropy Environmentalists, Inc., prepared for U.S. EPA, February 28, 1991.

[64] Technical Letter Reports to EPA by Entropy Environmentalists, Inc., 1/11/91, and 2/4/91.

[65] See section C on SO_2 monitoring above. Except where noted, the rationales for the various certification and quality assurance tests for flow monitoring are similar to those discussed in detail in section C, and are not repeated in this section.

[66] See figures 2 and 3 in E31, EPA Issue Paper, Flow Monitoring, prepared for the Acid Rain Advisory Committee (ARAC), April 1991.

[67] The three sites are CIPS Newton Unit =1, Big Rivers Electric Wilson Station, and Southeast Resource Recovery Facility (SERFF).

Concern has been raised by some electric utility representatives about the accuracy of flow monitor measurements of average flue gas velocity when flue gas stratification occurs. Bends or projections in the stack or duct may cause flow disturbances leading to flue gas stratification. EPA has sponsored a study of flow stratification in various shapes and sizes of flues to determine whether single-point, three-point, and line flow monitors [68] could be properly situated so they would obtain accurate measurements of average flue gas velocity.[69] This study indicates that, in general, properly situated flow monitors of all three types can achieve relative accuracies of 10 percent or less even when flue gas stratification occurs. An exception is the single-point flow monitor, which often cannot be situated so as to produce as consistently accurate measurements as the other monitors in either circular or rectangular flues. However, since additional evidence indicates that single-point pitot tubes can achieve this accuracy in many applications,[70] the proposed rule allows the use of single-point flow monitors wherever they meet the applicable performance specifications.

Analyses of recent test data on ultrasonic and thermal flow monitors suggest that substantially better performance could be obtained with today's technology by properly calibrating the monitors to minimize instrument inaccuracy.[71] Apparently, some operators are not cognizant of (and thus, do not use) the flow monitor calibration adjustment procedures in 40 CFR part 52, appendix E, which could significantly improve monitor relative accuracy. EPA estimates that if these calibration procedures were regularly and properly implemented to minimize instrument bias, relative accuracies could be significantly improved beyond the 10 percent level.[72]

The foregoing discussion notwithstanding, many electric utility industry representatives remain concerned that a relative accuracy of 10 percent may not be achievable in all situations, especially at the startup of the program. As evidence of this, they have pointed to the relative accuracy values in the EPA database that are above 10 percent (none are above 15 percent). Industry representatives have also questioned the representativeness of the database for low-flow situations, which are thought to be especially problematic. Many utility representatives felt much more confident of being able to meet a standard of 15 percent, given their lack of operating experience to date. In recognition of their concern, and of the limited database to which EPA had access, the proposed rule sets the limit for relative accuracy at 15 percent during Phase I of the acid rain program, i.e., through December 31, 1999.

Electric utility representatives also voiced concern that some retrofit situations may prove to be more difficult than those cited in the database. Particular concern was voiced that some units may not be able to meet the siting criteria in the Reference Method 1, or that duct flow characteristics may prevent the attainment of the desired accuracy. These representatives suggested that operators who undertake good faith installation and use of flow monitoring devices, which nevertheless fail to meet the required relative accuracy, not be forced into extensive, expensive studies, relocation, and/or new stack construction, but instead be allowed to adjust the data upward to account for the less accurate result. EPA expressly requests comment on this potential alternative approach.

In addition to comments on the achievable performance of flow monitors, participants in ARAC and in informal discussions recommended the adoption of a combined-system performance standard for the combined flow-SO_2 monitoring system. Such a standard reflects the precedent of Subpart Da, which requires a combined-system standard for the SO_2–diluent system as well as the NO_x-diluent system. Moreover, such a combined-system relative-accuracy standard, expressed in percentage terms, would be derived from mass units (pounds or tons of SO_2), rather than being based on flow units or concentration units, as are the component monitor standards. Since the reductions required by the Act are stated in terms of mass units, setting an accuracy requirement directly in terms of these mass units would provide more direct assurance that the primary goal of the legislation is being met. A relative accuracy of 10 percent was suggested in these discussions as the appropriate combined-system standard.

Based on the available data, analysis, and discussions, EPA proposes to phase in flow monitor relative accuracy standards. The initial standard reflects current achievement by existing monitors, and is designed to provide sources time to obtain operating experience sufficient to achieve the subsequent, more stringent standard. The requirement to meet a combined SO_2–flow system relative accuracy standard would also be phased in, for the same reasons. The flow monitor relative accuracy standard would be set at 15 percent through December 31, 1999, decreasing to 10 percent beginning on January 1, 2000, the date of the start of Phase II of the Acid Rain program. The combined-system relative accuracy standard would be set at 10 percent, becoming effective on January 1, 2000. As the deadline for implementation of the Phase II standards approaches, EPA will evaluate the experience gained under Phase I of the program and assess any potential problems of these Phase II requirements.

Today's proposal also includes provisions for obtaining exceptions to the requirements in cases where it can be demonstrated that flow monitors cannot be installed consistent with the siting criteria of Reference Method 1. It also includes a less-stringent alternative standard for low-flow situations, based on the results of an EPA study of monitor performance.[73] The proposed alternative standard would apply to units where the average stack gas velocity during the RATA is less than or equal to 10 feet per second, and is defined as an absolute limitation on monitor inaccuracy of ± 1 foot per second, as specified by procedures in Appendix A of the proposed rule.

b. *Bias.* As discussed previously with regard to SO_2 monitor certification, the relative accuracy statistic combines statistical descriptors of bias and precision in a manner that allows monitors with significant bias (measuring consistently low or high relative to true flow) to achieve "acceptable" relative accuracy. Accordingly, EPA is proposing that flow monitors satisfy a bias standard, in addition to the relative accuracy standard, in the performance specification tests for certification. The proposed rule requires that bias be evaluated at normal load only. In EPA's judgment, evaluation and adjustment for bias, as described below, would be too complex and unwieldy to apply at more

[68] Single-point flow monitors measure at only one point in the flue gas stream, whereas three-point and line flow monitors measure at three points and more than three points, respectively.

[69] "Velocity Stratification," Entropy Environmentalists, Inc., prepared for U.S. EPA, February 28, 1991.

[70] Data from Energy and Environmental Measurements Corporation (EEMC) on single-point differential flow monitors.

[71] EPA test data from Big Rivers and SERRF test sites, April 1991.

[72] Technical correspondence from A. Wayne, May 30, 1991.

[73] "Technical Guidance on Selected Flow Monitoring Procedures and Equipment: Flow Monitor Performance Evaluation, CIPS, Newton, Illinois, Volumes I and II," Entropy Corporation, 5/31/91.

than one load condition. Moreover, since the adjustment for bias would be applied to data at all load conditions, EPA believes that any understatement of emissions due to bias would be adequately addressed, and little would be gained by differentiating the adjustment according to load.

For the reasons discussed previously in the context of SO_2 pollutant concentration monitor certification, EPA has selected a t-test as the most satisfactory method for screening out flow monitors that measure consistently low or high relative to the reference method reading. This test, applied at the 95-percent level of confidence to detect low bias only,[74] would use the same data as that used for certifying relative accuracy at normal load. The recorded flow data from a monitor that fails a bias test would not be considered invalid, or "missing," but would be adjusted upward to compensate for the bias using the method shown in appendix A of the rule. Monitors failing the test would be certified by incorporating the aforementioned data adjustment factor, which would be applied to all data recorded between the time of the failed certification bias test and the time of the next successful bias test. Sources would have the option of continuing to apply the bias-adjustment factor to their monitor readings or eliminating the source of the bias. The bias adjustment factor would be applied to all monitor readings until a new RATA is conducted in which the relative accuracy standard is met and the bias test is passed. In the new RATA, if the unit passes the relative accuracy test but again fails the bias test, the bias adjustment factor would be recomputed based on the new RATA values and this new factor would be applied to subsequent monitor readings.

Preliminary findings from EPA's on-site flow monitor evaluations suggest that this standard could be achieved by well-maintained flow monitors based on current technology, assuming they are properly calibrated using the procedures in 40 CFR part 52, appendix E.

c. *Electronic Stability/Calibration Error.* EPA proposes that a daily electronic stability test be required under the Acid Rain program for flow monitors that do not perform daily calibration error tests. The proposed procedures specify that the electronic drift of the flow monitor at 40–75 percent of span and at 80–100 percent of span not deviate from the value of the reference input signals by more than three percent. For flow monitor certification, the electronic drift would be determined once every 24 hours for seven consecutive days.

In contrast to an electronic drift test, which detects change, or "drift," over time in the electronic signals of the monitor, a calibration error test compares the monitor reading with a control standard generated by the instrument. Because not all available monitors can currently perform the more demanding calibration error test, EPA is not proposing to require this test for all flow monitors.[75] EPA is concerned that requiring the proposed daily calibration error test may be unnecessary for differential pressure flow monitors that perform automatic, timed periodic back purging, simultaneously on both sides of the probe, of sufficient force and frequency to keep the probe free of obstructions, and that provide an automatic drain for wet gases. An option to the proposed daily calibration error test for this type of flow monitor would be to perform a full-system calibration error test from the point outside the stack (or duct) where the probe enters the stack wall through the data acquisition and handling system. EPA specifically requests comment on whether this approach would be sufficient to guarantee the accuracy of the data on a daily-certifiable basis.

Even though calibration error tests are not required for all types of flow monitors in today's proposal, EPA would like to encourage all sources to perform calibration error tests where possible, and to encourage vendors to develop such tests, since they can detect problems in monitor performance regularly and promptly (i.e., within one day) and because, in EPA's judgment, they are likely to foster better maintenance. Therefore, as discussed in Section 3 below, EPA is proposing less-frequent relative accuracy testing frequencies for flow monitors performing daily calibration error tests. This reduced frequency is both a recognition of the reduced need for relative accuracy testing when calibration error testing is performed, and an incentive to sources to perform calibration error testing.

d. *Orientation sensitivity.* EPA's flue gas stratification study and the on-site flow monitor evaluation tests, discussed above, have shown that the average flue gas velocity measurements from differential pressure and thermal flow monitors are sensitive to the monitor's orientation with respect to the axial component of flue gas flow. Specifically, misalignment of the flow monitor can produce average flue gas velocity measurements that are not representative of true flow. EPA proposes to adopt the orientation sensitivity test procedures in 40 CFR part 52, appendix E, for certification of flow monitors that are sensitive to the flow direction of the gas. These procedures specify that no gas velocity measurement shall deviate from the zero-degree orientation value by more than four percent.

e. *Interference checks.* Flow monitors may be susceptible to fouling or plugging of that portion of the flow monitor in contact with the flue gas. Accordingly, the proposed rule requires flow monitors to provide an automatic timed periodic back purging or equivalent method to keep the surfaces in contact with the flue gases clean and free of obstructions. The proposed rule requires an automatic drain for wet gases for self-averaging differential pressure flow monitors, and a method for detecting leaks or pluggage in differential pressure flow monitors. The proposed rule also requires all flow monitors to provide a method (a manual check is acceptable) for zeroing and calibrating the transducer. According to the flow monitor vendor survey discussed above, current U.S. suppliers of flow monitors would be able to comply with this requirement for flow monitor certification under the Acid Rain program.

3. Quality Assurance and Quality Control Procedures

The quality assurance (QA) and quality control (QC) procedures EPA is proposing for flow monitors under the Acid Rain program are similar in purpose to those discussed earlier in connection with SO_2 concentration monitors. These QA/QC procedures consist of a series of tests to be performed periodically (daily, quarterly, semi-annually, and annually) to ensure that the monitors, once certified, continue to operate reliably and accurately. In addition to the tests on the individual monitors, beginning in 2000 certain QA/QC procedures would also be performed on the combined system consisting of the SO_2 monitor and flow monitor.

Also included in the QA/QC procedures are specifications for maintaining records of QA/QC test

[74] As previously noted, considering only low-biased results as failures in the t-test at the 95-percent level of confidence is statistically equivalent to employing a one-tailed t-test with alpha equal to 0.025. Thus, in table 8–1 in appendix A of the regulations, the appropriate t-values are denoted by $t_{0.025}$.

[75] Ultrasonic flow monitors can perform a daily zero-and-span check, which is in effect a 2-point calibration error test. EPA is proposing to require this test for ultrasonic monitors. Vendors of other types of flow monitors indicate they may soon develop comparable tests.

dates, descriptions, and results and for the submission of quarterly Data Assessment Reports to EPA and other applicable regulatory authorities.

a. *Daily assessments*. EPA believes that it is important to the integrity of the monitoring system that any errors in flow monitor performance be identified as quickly as possible. Therefore, the proposed rule requires a daily performance check of flow monitors. The various types of flow monitors (ultrasonic, differential pressure, and thermal) use different measurement principles, and are therefore prone to different kinds of performance problems. EPA has not been able to devise a generic method for daily performance checks of flow monitors, as is proposed for SO_2 pollutant concentration monitors. Accordingly, EPA is proposing either a daily electronic stability test or a daily calibration error test for all flow monitors and other "tailored" performance checks, as appropriate.

EPA is proposing to adopt the daily zero and calibration drift requirements specified in 40 CFR part 52, appendix E, for daily checks of the electronic stability of all flow monitors under the Acid Rain program. These provisions require that a test to ensure that the flow monitor continues to meet the manufacturer's specifications for zero and calibration drift be performed at 24-hour intervals, or more frequently if recommended by the manufacturer. Under the proposed rule, the standard for the daily electronic stability check would be the same as that proposed for the flow monitor calibration error test (i.e., within three percent).

For ultrasonic flow monitors, EPA proposes to require daily electronic tests of both zero and span (high-level) values, analogous to the daily calibration error tests required for pollutant concentration monitors. Such daily checks are needed to validate proper operation of this flow monitor's electronically induced sound bursts for measuring gas velocity. EPA believes that these required tests are analogous to that performed by pollutant concentration monitors, and thus would qualify for reduced-frequency relative accuracy testing, as discussed in the section on quality assurance and quality control procedures.

For differential-pressure flow monitors that perform automatic, timed, periodic back purging, simultaneously on both sides of the probe, of sufficient force and frequency to keep the probe and signal lines free of obstructions, and that provide an automatic drain for wet gases, EPA proposes to require either an electronic drift test or a calibration error test. Monitors performing the latter test would qualify for reduced-frequency relative accuracy testing, as discussed in the section on quality assurance and quality control procedures. The calibration error test for these types of flow monitors would be a full system test from the probe tip through the data acquisition and handling system. However, as discussed previously in the section on electronic stability/calibration error, EPA solicits comment on whether the proposed calibration error test for this type of flow monitor is necessary.

For thermal flow monitors, EPA proposes to require thermal probe inspection and cleaning at a frequency that ensures the probe remains clean at all times.

The recorded flow data from a flow monitor that fails any of the required daily performance checks would be considered invalid, or "missing," prospectively until corrective action is taken and the monitor passes the check.

b. *Periodic performance tests*. For the same reasons outlined earlier in this preamble in the section describing periodic performance tests for SO_2 concentration monitors, EPA proposes to require periodic relative accuracy test audits (RATAs) and bias tests on flow monitors. Sources that conduct daily calibration error tests on their flow monitors would perform RATA/bias tests on a semi-annual basis; others would be required to conduct RATA/bias tests on a quarterly basis. Both these frequencies could be reduced further with superior RATA performance, as outlined below.

The recorded flow data from a monitor that fails a RATA would be considered invalid, or "missing," prospectively until corrective action is taken and the monitor achieves the required relative accuracy standard. For monitors that fail a bias test, subsequent monitor measurements would be adjusted upward to compensate for bias or, at the source's option, the test could be repeated as appropriate to demonstrate that corrective measures were successful.

I. Relative Accuracy Test Audit

For those flow monitors that perform daily calibration error tests, EPA proposes to require semi-annual nine-run relative accuracy test audits (RATAs) of flow monitors for the Acid Rain program. These tests would alternate on a six-month cycle between a three-load test and a one-load test. The three-load test would be identical to the relative accuracy test described previously for monitor certification; the one-load test also would be identical to the certification test, except that it would be performed at normal load only.

For monitors that do not perform daily calibration tests, quarterly RATAs would be required. For three of the four quarters, the RATA would be run at normal load only; every fourth quarter, the test would be run at three loads, as in the certification test for relative accuracy. In EPA's judgment, this higher frequency is necessary because without daily calibration it is much more likely that relative accuracy will degrade over time. It is hoped that this dual-frequency requirement will provide sources an incentive to perform daily calibration where possible, and also induce vendors to develop applicable test methods.

Monitors would be required to attain a relative accuracy of 15 percent in Phase I of the program (i.e., through December 31, 1999), and 10 percent in Phase II (beginning January 1, 2000. In addition, in Phase II, (beginning January 1, 2000) the combined SO_2/flow monitoring system would also be required to meet a combined-system relative accuracy standard of 10 percent.

As in the case of SO_2 monitors, flow monitors achieving a relative accuracy significantly better than the standard would be allowed to decrease the RATA frequency. That is, in Phase I, flow monitors achieving a relative accuracy of 10 percent or better could reduce their RATA frequency from semi-annual to annual, or from quarterly to semi-annual for those monitors not tested daily for calibration error. In Phase II, the threshold would be lowered to 7.5 percent.[76] As long as the monitor maintained these improved relative accuracies, the reduced RATA frequency would remain in effect. Under these reduced frequencies, one test per year would be required to be a three-load test. Table 4 summarizes the required RATA frequency as a function of achieved relative accuracy.

TABLE 4.—RATA FREQUENCY FOR FLOW MONITORS

Relative accuracy		Required RATA frequency	
Phase I	Phase II	Daily cal	No daily cal
≤15%	≤10%	Semi-annual	Quarterly.
≤10%	≤7.5%	Annual	Semi-annual.

[76] Sources meeting the relative accuracy requirement (15% in Phase I, 10% in Phase II) but not achieving a relative accuracy sufficient to qualify for reduced RATA frequency (10% in Phase I, 7.5% in Phase II) would be allowed two tries (i.e., they could collect two sets of RATA data) to achieve these superior relative accuracies and thereby lower their RATA frequency.

2. Bias Test

EPA proposes to require bias tests of flow monitors at normal operating load under the Acid Rain program. These tests would use the relative accuracy test audit data for normal load, would be performed at the same frequency as the relative accuracy test audits, and would be identical to the bias test described previously for monitor certification. The performance standard would be that used for certification, i.e., the data would be required to pass a t-test, applied to detect low bias only, at the 95-percent level of confidence. Data that fails the test would not be considered invalid, or "missing," but would be adjusted upward to compensate for the bias, using the method shown in Appendix A of the rule, until corrective action is demonstrated in a subsequent bias test. Sources would have the option of continuing to apply the bias-adjustment factor to their monitor readings or eliminating the source of the bias. The bias adjustment factor would be applied to all monitor readings until a new RATA is conducted in which the relative accuracy standard is met and the bias test is passed. In the new RATA, if the unit passes the relative accuracy test but again fails the bias test, the bias adjustment factor would be recomputed based on the new RATA values and this new factor would be applied to subsequent monitor readings.

As proposed, the bias test could be re-taken at any time at the source's option. As discussed earlier in section C on SO_2 monitors, some have voiced concern that sources might re-run the test many times, "shopping" for a lower adjustment factor. EPA invites comment on the importance of this problem and on regulatory approaches to address it.

E. NO_x Emissions Monitoring

Since the Act's limitations on NO_x emissions are expressed in terms of annual emission rate averages (in lbs/mmBtu), the monitoring requirements for NO_x emissions under the Acid Rain program will necessarily differ somewhat from those for SO_2 emissions. Specifically, the continuous monitoring of a diluent gas exhausting from the boiler, either O_2 or CO_2, would be required to convert NO_x ppmv measures from a NO_x pollutant concentration monitor into NO_x mass emission rates relative to the heat input of the fuel. The proposed rule would define a "NO_x continuous emission monitoring system" as the combination of a pollutant concentration monitor and a diluent gas monitor, as is done under Subpart Da. Therefore, annual monitor availabilities, relative accuracy and bias standards, and some other performance specifications in the proposed rule would refer to the NO_x continuous emission monitoring system, not the NO_x pollutant concentration monitor.

Analogous to the SO_2 pollutant concentration monitoring assessment, however, EPA has relied upon the historical operating experience of NO_x continuous emission monitoring systems at units subject to subpart Da requirements to develop proposals for: (1) Design of monitoring protocol, including sampling frequency and the time period for emissions accounting; (2) performance specification parameters for certifying monitoring systems, including relative accuracy, bias, calibration error, and cycle time/response time; and (3) quality assurance and quality control procedures, including daily calibration error tests and periodic relative accuracy test audits, bias tests, and calibration error tests. EPA is proposing to use the applicable provisions of subpart Da for the NO_x emissions monitoring requirements under the Acid Rain program where they continue to define the performance achievable with current technology, provided they are consistent with the program's goals and monitoring objectives.

While the form of NO_x emissions monitoring would differ from that of SO_2 emissions monitoring under the Acid Rain program, EPA believes that the monitoring objectives are essentially the same for both acid deposition precursors. The Act's requirement "to analyze, measure, and provide on a continuous basis a permanent record of emissions" applies to NO_x as well as SO_2. EPA believes that 100 percent accounting of NO_x emissions is required to: (1) Develop viable annual NO_x emission rate averages for affected units, and (2) implement the annual NO_x emissions averaging pools allowed under the Act. Further, accurate and complete NO_x emissions data are needed from all units for the Congressionally-mandated evaluation of the environmental and economic consequences of interpollutant (SO_2 for NO_x) allowance trading.

1. System Design Considerations

a. *Time period for emissions accounting.* For the reasons discussed previously with regard to SO_2, EPA has concluded that an hour should be the basic building block in accounting for NO_x emissions under the Acid Rain program.

b. *Sampling frequency.* EPA proposes to adopt subpart Da's requirement that a continuous emissions monitoring system should be capable of taking measurements at least every 15 minutes (four sampling or data points per hour) for NO_x monitoring systems under the Acid Rain program. Subpart Da of 40 CFR part 60, however, allows that hourly emissions data are acceptable for compliance purposes if the monitor captures at least two (out of the four) data points [60.47(a) and 60.47(b)]. The intent of this provision, as described in the NSPS Preamble (44 FR 33581, June 11, 1979), was to accommodate instruments that cannot obtain four equally spaced points during calibration periods.

Analogous to the procedure used for SO_2 and flow data, EPA is proposing to allow the calculation of average hourly NO_x emission rates (in lbs/mmBtu) using two data points, each representing a 15-minute period, of the normally required four (or more) data points during hours when maintenance, repair, calibration error tests or other quality assurance activities specifically required by this part are being performed.

2. Performance Specifications for Certification

EPA proposes to require the certification of a NO_x continuous emission monitoring system, as is done under Subpart Da, before that monitoring system may be used to satisfy any of the emissions monitoring requirements under the proposed rule. This certification process would involve the series of tests described previously for SO_2 pollutant concentration monitors, except that most tests would be performed on the monitoring system (pollutant concentration monitor and diluent gas monitor) and test results would be on a lbs/mmBtu basis.

a. *Relative accuracy.* Under the proposed rule, the performance specification tests for certifying NO_x continuous emission monitoring systems would be similar to those described previously for SO_2 pollutant concentration monitors.[77] Both SO_2 and NO_x performance specification tests would consist of at least nine sets of paired comparisons between monitor measurements and contemporaneous reference method measurements of pollutant emissions in the exhaust gas. Reference method test results are assumed to be equivalent to the true values of the pollutant emissions, which

[77] See Section C on SO_2 monitoring above. Except where noted, the rationales for the various certification and quality assurance tests for NO_x monitoring are similar to those discussed in detail in Section C, and are not repeated in this Section.

are unknown. EPA has defined six acceptable reference methods for evaluating the accuracy of NO_x continuous emission monitoring systems (40 CFR part 60, appendix A, methods 7, 7A, 7B, 7C, 7D, and 7E). Most units subject to subpart Da requirements currently use either method 7 (wet chemistry) or method 7E (instrumental).

The NO_x performance specification tests would be performed on the monitoring system (pollutant concentration monitor and diluent gas monitor) and measured in lbs/mmBtu. Unlike the SO_2 monitoring system requirements, the individual NO_x pollutant concentration monitors are not required to meet an independent relative accuracy standard of performance.

Subpart Da established a relative accuracy of 20 percent as the standard for defining acceptable NO_x monitoring system performance with respect to the accuracy of emissions measurements. EPA analysis of the relative accuracies reported by NO_x continuous emission monitoring systems at units subject to Subpart Da requirements, referenced previously, indicate that over 70 percent of these systems meet a relative accuracy standard of 10 percent. Subpart Da, however, affords low-emitting units the option of using an alternative (less stringent) standard, which is defined for NO_x as 10 percent of the applicable emissions standard (in lbs/mmBtu). As discussed previously, subpart Da provides this optional alternative standard for low-emitting units because the mathematical construction of the relative accuracy statistic may make it more difficult for them to satisfy the normal criterion.

Because of the importance of accurate emissions measurements to NO_x annual averages, the NO_x emissions averaging pools, and other flexible components of the program, EPA is proposing a relative accuracy of 10 percent as the standard for defining acceptable NO_x continuous emission monitoring system performance under the Acid Rain program. EPA believes that this relative accuracy standard more closely reflects the performance that could be achieved by well-maintained systems based on current technology than does subpart Da's 20-percent standard.

Like subpart Da, EPA is also proposing a less stringent alternative standard for low-emitting units, although it is not as clear from the available data where the relative accuracy statistic becomes problematic. EPA has not completed its statistical analyses of NO_x RATA data from units subject to Subpart Da requirements. Accordingly, the proposed rule uses the cutoff established for SO_2 emission rates, or 0.5 lb/mmBtu. The optional alternative standard for low-emitting NO_x units would be defined as an absolute limitation of $\pm$0.05 lb/mmBTU on monitoring system inaccuracy. Because the available data does not clearly indicate the need for this cutoff point, EPA specifically requests comment on both the appropriateness of this cutoff rate and the level at which the exception is proposed.

b. *Bias*. Under the proposed rule, NO_x continuous emission monitoring systems would have to satisfy a bias test, in addition to achieving an acceptable relative accuracy in the performance specification test, for certification. EPA is proposing a t-test, analogous to the tests described for SO_2 pollutant concentration and flow monitors, for the NO_x continuous emission monitoring system. NO_x monitoring systems would be required to pass a t-test, applied to low bias only,[78] at the 95-percent level of confidence. The recorded NO_x emission rate data from a monitoring system that fails a bias test would not be considered invalid, or "missing," but would be adjusted upward to compensate for the bias using the method shown in Appendix A of the rule. Monitoring systems failing the test would be certified by incorporating the aforementioned data adjustment factor, which would be applied to all data recorded between the time of the failed certification bias test and the time of the next successful bias test.

Based on preliminary statistical analyses of NO_x RATA data for units subject to subpart Da, EPA believes that the proposed standard can be achieved by well-maintained NO_x monitoring systems using current technology.

c. *Calibration error*. As a result of the NO_x emissions averaging provisions under the Acid Rain program, EPA believes that units will operate over a substantially wider range of NO_x emissions rates than those experienced under Subpart Da. NO_x emissions must be measured accurately throughout the entire range of expected emission rates in order to develop viable annual NO_x emission rate averages, particularly for units averaging their emissions with others. Accordingly, EPA is proposing to require three-point calibration error tests, identical to those described previously for SO_2 pollutant concentration monitors, for certification of NO_x pollutant concentration monitors and diluent gas monitors. In contrast to the relative accuracy and bias specifications which apply to the NO_x continuous emission monitoring system as a whole, calibration error standards apply to the pollutant concentration monitor and the diluent gas monitor separately.

EPA also proposes to use Subpart Da's performance specification of 2.5 percent of calibration error for certification of NO_x pollutant concentration monitors and diluent gas monitors under the Acid Rain program. That is, to qualify for certification, the monitor's measurements of the pollutant (NO_x) or gaseous constituent (O_2 or CO_2) shall not deviate from the known values by more than 2.5 percent for each of three concentration (low, mid-range, and high) levels.

d. *Cycle time/Response time*. EPA proposes to adopt the cycle time/response time test required under Subpart Da for certifying NO_x continuous emission monitoring systems under the Acid Rain program. A description of this test may be found in the section on performance specifications for certification of SO_2 pollutant concentration monitors. Subpart Da's performance specification of 15 minutes as the maximum time allowed for each stepchange would also apply.

3. Quality Assurance and Quality Control Procedures

The quality assurance (QA) and quality control (QC) procedures EPA is proposing for NO_x continuous emission monitoring systems under the Acid Rain program are essentially equivalent to those detailed previously for SO_2 pollutant concentration monitors, except that they would generally apply to the combined monitoring (pollutant concentration monitor and diluent gas monitor) system. These QA/QC procedures consist of a series of tests to be performed periodically to ensure that the continuous emission monitoring systems, once certified, continue to operate reliably and accurately. Also included are specifications for maintaining records of QA/QC test dates, descriptions, and results and for the submission of quarterly Data Assessment Reports to EPA and other applicable regulatory authorities. These latter requirements are discussed later in the section on recordkeeping and reporting.

a. *Daily calibration error test*. Analogous to the daily calibration tests for SO_2 pollutant concentration monitors, EPA is proposing to expand subpart Da's daily calibration drift

[78] Considering only low-biased results as failures in the t-test at the 95-percent level of confidence is statistically equivalent to employing a one-tailed t-test with an alpha value of 0.025. Thus, in Table 8-1 in appendix A of the regulations, the appropriate t-values are denoted by $t_{0.025}$.

checks for NO_x pollutant concentration and diluent gas monitors into daily calibration error tests so as to quality assure the recorded emissions data on a daily basis. Under the Acid Rain program, affected units would be required to use standard reference material or Protocol 1 gases for these daily calibration error tests in addition to the quarterly calibration error tests.

As discussed previously, accurate NO_x emissions measurements are essential to successful implementation of NO_x annual averages, the NO_x emissions averaging pools, and other flexible components in the Acid Rain program. Accordingly, EPA is proposing to apply the same calibration error standard to the NO_x pollutant concentration monitor and the diluent gas monitor as is being proposed for the SO_2 pollutant concentration monitor. That is, EPA proposes that drift should not exceed 5 percent in a given day. The recorded emissions data from a monitor that fails this calibration error standard would be considered invalid, or "missing," prospectively until monitor error is brought within specification.

b. *Periodic performance tests.* For the same reasons outlined earlier in this preamble in the section describing periodic performance tests for SO_2 concentration monitors, EPA proposes to require two semi-annual performance tests, a relative accuracy test audit (RATA) and a bias test, on NO_x monitoring systems. Quarterly three-point calibration error tests on the NO_x concentration and diluent gas monitors would also be required. The recorded NO_x emissions rate data from a monitoring system that fails a RATA, or the concentration data from a monitor that fails a calibration error test, would be considered invalid, or "missing," prospectively until corrective action is taken and the monitor or monitoring system achieves the required standard. Data that fails a bias test would be adjusted to compensate for bias or, at the source's option, the test could be repeated after corrective action is taken to demonstrate that the correction is no longer necessary. Here, as in the case of SO_2 concentration monitors, the achievement of superior relative accuracy in a given RATA would decrease the required frequency of future testing from semi-annual to annual.

1. Relative Accuracy Test Audit

EPA proposes to require semi-annual relative accuracy test audits of NO_x monitoring systems. These tests would be identical to the tests described previously for certification, and the same performance standard (relative accuracy of 10 percent) would apply. As in the case of SO_2 monitors, NO_x monitoring systems achieving a relative accuracy of 7.5 percent or better would be allowed to decrease the RATA frequency from semi-annual to annual as long as relative accuracy remains at 7.5 percent or better.[79] Table 5 summarizes the required RATA frequency as a function of achieved relative accuracy.

TABLE 5.—RATA FREQUENCY FOR NO_x MONITORING SYSTEMS

Relative accuracy	Required RATA frequency
≤10%	Semi-Annual.
≤7.5%	Annual.

2. Bias Test

The periodic bias tests on NO_x monitoring systems for the Acid Rain program would be conducted with the same frequency and at the same time as the RATA's, would employ the RATA data, and would be identical to the bias test described previously for monitoring system certification. The proposed performance standard for NO_x monitoring systems in the bias test is also identical to that proposed for monitoring system certification. That is, under the proposed rule, NO_x monitoring systems would be required to pass a t-test, for low bias only, at the 95-percent level of confidence. As discussed previously, the recorded NO_x emission rate data from a monitoring system that fails a bias test would not be considered invalid, or "missing," but would be adjusted upward to compensate for the bias, using the method shown in appendix A of the rule, until corrective action is demonstrated in a subsequent bias test. Sources would have the option of continuing to apply the bias-adjustment factor to their monitoring system readings or eliminating the source of the bias. The bias adjustment factor would be applied to all monitoring system readings until a new RATA is conducted in which the relative accuracy standard is met and the bias test is passed. In the new RATA, if the unit passes the relative accuracy test but again fails the bias test, the bias adjustment factor would be recomputed based on the new RATA values and this new factor would be applied to subsequent monitoring system readings.

As proposed, the bias test could be re-taken at any time at the source's option. As discussed earlier in section C on SO_2 monitors, some have voiced concern that sources might re-run the test many times, "shopping" for a lower adjustment factor. EPA invites comment on the importance of this problem and on regulatory approaches to address it.

3. Three-Point Calibration Error Test

EPA proposes to require a quarterly three-point calibration error test on NO_x concentration monitors and diluent gas monitors. This test would be identical to the three-point calibration error test described previously for monitor certification, except that the performance standard would be the same as that used for the daily calibration error test. That is, under the proposed rule, a monitor's measurements of NO_x or diluent concentration shall not deviate from the calibration gas value by more than 5 percent for each of three concentration levels (low, mid-range, and high).

F. Missing Data Procedures

Section 412(d) of the Act provides for specific methods for calculating emissions during periods when data from a CEMS or an approved alternative monitoring system are unavailable. The Agency is required to deem the unit to be operating in an uncontrolled manner during the entire period for which the data are not available unless the owner(s) and operator(s) can provide information satisfactory to the Administrator on emissions during that period. Further, EPA must prescribe a standard method to calculate emissions for missing data periods in the Acid Rain CEMS regulation.

In deliberations regarding the most appropriate procedures for filling in missing emissions data, the Agency has identified several goals that the procedures should satisfy. They are: (1) To provide strong incentives for effective CEMS operation and maintenance programs, thus yielding high CEMS availability and data capture rates; (2) to use less-conservative methods for estimating probable actual emissions for missing data when annual monitor availability exceeds specified thresholds and missing data periods are relatively short; (3) to use more conservative methods for filling in missing data when annual monitor availability falls below specified thresholds and/or missing data periods are longer; (4) to develop procedures for filling in missing data that provide

[79] Sources meeting the 10% requirement but not achieving a relative accuracy of 7.5% or better would be allowed two tries (i.e., they could collect two sets of RATA data) to achieve 7.5%, and thereby lower their RATA frequency.

incentives to use CEMS as the primary method for determining emissions; (5) to develop procedures that are automatic in their execution, relying only on the CEMS-generated emissions database, thereby minimizing the need for enforcement actions and supporting the smooth and unambiguous operation of the program; and (6) to develop procedures that are readily implementable by all affected units. The ARAC Emissions Monitoring Subcommittee has, in general, endorsed these goals, although a few members did not concur with the concept of requiring an annual monitor availability threshold.[80] EPA requests comment on whether the proposed procedures satisfy the aforementioned criteria and goals for this program.

The Agency prepared two issue papers on potential procedures for filling in missing emissions data.[81] Simultaneously, UARG has been conducting an extensive series of Monte Carlo simulations and a case study using actual hourly SO_2 concentration data from a Subpart Da unit to develop statistical methods that could be used to fill in missing data without significant loss of accuracy in the annual accounting of SO_2 emissions.[82] Both the EPA and UARG studies cited above address only missing SO_2 data. UARG has also submitted a study presenting a method of correlating flow data with unit load data for purposes of missing flow data substitution.[83] EPA has not identified any comparable analyses for missing NO_x emission data.

The UARG studies on SO_2 missing data suggest that statistical estimation methods can be used to fill in missing SO_2 concentration data for periods of short duration above a specified monitor availability threshold without jeopardizing the accuracy of year-end totals for SO_2 emissions. The ARAC Emissions Monitoring Subcommittee found that statistical methods look promising for filling in short-duration data gaps as long as high annual monitor availability is maintained. The Subcommittee did not reach consensus, however, on the exact value(s) of appropriate monitor availability threshold(s), although the range was narrowed to between 90 and 95 percent. Most members endorsed the concept of using graduated monitor availability thresholds. The Subcommittee also did not agree on the appropriateness of using statistical methods for filling in missing data periods longer than three hours.[84]

In various discussions on this matter, other industry representatives have indicated that the prompt corrective action that EPA wants to encourage when the CEMS system malfunctions sometimes requires more than 3 hours to complete. As a result, they have suggested that a first tier "cutoff" value of 6 hours appears to be more appropriate. Others have suggested that such corrective action could usually be completed within an 8-hour work shift, and have suggested 8 hours as the appropriate value for the first tier cutoff. In today's proposal, 6 hours was selected as the most appropriate first-tier cutoff value, based on EPA's judgment that most corrective action can be completed within that time. EPA requests comment on the appropriateness of this or other choices for the cutoff value defining Tier I.

EPA has also received suggestions on the most appropriate substitute value to select from a given lookback period. As discussed earlier, the value chosen as a substitute must be designed to be conservative (i.e., it must be more likely to be an overestimate than an underestimate), and it should be increasingly conservative as the lookback period gets longer. EPA considered using the highest value over a given lookback period as the substitute value. However, others have suggested that selecting the highest value in a given lookback period may catch an anomalous outlier value not reflecting actual conditions, and have thus suggested the use of another value such as the second-highest, the third-highest, the average of the top five, or the 90th percentile.

EPA considered all these possibilities, finding each of them to exhibit at least one of the aforementioned problems in some degree. The second- or third-highest value or an average of several high values could still suffer from the outlier problem. The 90th-percentile value avoids this problem entirely. However, any percentile-based approach has the drawback of not always preserving the desired property of being more conservative as the lookback period gets longer, and may be less than the actual emission value approximately ten percent of the time. In cases where this occurs, the percentile-based approach would not provide operators the intended incentive to restore the monitor to operation as quickly as possible. Nevertheless, by using the 90th percentile as opposed to average data, the missing data procedure will normally be conservative relative to the expected value.

After weighing the aforementioned factors, EPA narrowed the list of candidates for missing data substitution to: a modified 90th-percentile approach, which was chosen for today's proposal and is described below, and an approach which selects the average of the five highest values as the missing data substitute. The modified 90th-percentile approach was selected because it completely avoids the outlier problem described earlier.

Today's proposal uses the 90th-percentile value as a replacement for missing data. EPA believes that the current pattern of monitor operating practice will continue, thus preserving the conservative property of the percentile approach. However, to protect against the possibility of unintended and possibly perverse incentives, EPA is proposing to require that emission values over the lookback period be correlated with the sulfur content of the fuel being burned, and that the 90th-percentile value be chosen from the set of values recorded at times when the sulfur content of the fuel burned matches that of the missing data period. Moreover, to protect further against the possibility of providing lower-than-actual missing data values, EPA has combined the percentile approach with the probable-actual approach, wherein estimates are generated by taking the average of the hours before and after the missing data period. By taking the higher of these two emission estimates, EPA believes that the potential to under-report emissions will be minimized. As a result, EPA requests comment on whether it is necessary to correlate sulfur concentration in the emissions with the sulfur content of the coal under the percentile approach so long as this proposed underreporting protection is retained. EPA has also considered suggestions that missing data might be filled in using a case-by-case regression

[80] E14—ARAC Emissions Monitoring Subcommittee Minutes, February 20–21, 1991.

[81] (1) Missing Data Periods, EPA Issue Paper for ARAC Discussion, January 18, 1991 (IIA–45); and (2) Alternative Proposals for Missing Data Periods, EPA Issue Paper for ARAC Discussion, May 1991 (E–27).

[82] These studies include: (1) Assessing Data Availability at Units Subject to Subpart Da New Source Performance Standards, prepared by Roberson Pitts, Inc., for UARG, September 1990; (2) Evaluation of Missing Data Estimation Methods, prepared by W. S. Pitts Consulting, Inc., for UARG, February 1991; (3) Evaluation of Missing Data Methods—Supplement: Application of Estimation Methods to Actual Hourly SO_2 Emissions Data, prepared by W. S. Pitts Consulting, Inc., for UARG, March 1991; and (4) Technical Note from W. S. Pitts on behalf of UARG to U.S. EPA on Effects of Skewing Missing Data Patterns, April 10, 1991.

[83] "Alternative Procedure for Estimating Volumetric Flow Rate," Technical Memorandum to UARG from Science Applications, Inc., 6/19/91.

[84] Acid Rain Advisory Committee (ARAC) Emissions Monitoring Subcommittee Minutes—February 20–21, 1991 and April 29–30, 1991.

analysis of emissions with fuel sulfur content for each fuel supply at each unit, and requests comment on this possibility as well.

In developing its proposal, EPA considered the average-of-the-top-five-values approach to be the most attractive alternative to the proposed percentile approach, since it avoids the potential for underreporting emissions while significantly reducing the possible impact of outlier values. Moreover, like the other non-percentile approaches, it eliminates the need to correlate fuel sulfur content with emission rate, thus simplifying the data system software requirements. EPA specifically requests comment on the relative merits of the average-of-the-top-five approach and the 90th-percentile approach proposed today. EPA also requests comment on the merits of other candidate missing data routines which would substitute the highest, second-highest, or third-highest values recorded during the specified lookback period.

1. Rejected Alternatives

Representatives of State agencies and environmental groups have urged EPA to promulgate regulations under the Acid Rain program that will encourage the use of backup CEMS hardware rather than statistical or other estimation methods for filling in missing emissions data, at least for high-emitting units. EPA has considered the option of requiring all units to install a duplicate certified CEMS to supply missing emissions data when the primary CEMS is not available. EPA has concluded that this would be a costly alternative if applied universally, and may not necessarily produce significantly more accurate emissions data if high annual monitor availabilities (on the order of 95 percent) are maintained.

In ARAC discussions, some have also requested EPA to consider proposing different procedures for filling in missing emissions data, depending on the reason for CEMS unavailability.[85] They have recommended limiting the use of less conservative statistical estimation methods to filling in missing data periods resulting from QA/QC activities and using more conservative methods for periods resulting from poor monitor maintenance. While EPA endorses the general principle of providing incentives for aggressive, effective CEMS QA/QC and preventative maintenance programs, a tally of the possible reasons for missing data has indicated that this approach would be exceedingly cumbersome to implement and enforce.

2. Proposed Approach

The proposed rule would use a modified form of the statistical estimation methods developed by UARG for filling in missing SO_2 concentration data in cases where availability is above specified thresholds and missing data periods are relatively short. Where availability falls below these thresholds, and missing data periods are longer, the proposed rule would require more conservative procedures within a given fuel sulfur content range. The procedures for NO_x and flow missing data would be similar to the SO_2 procedures, but would incorporate correlations between load and emissions or flow data rather than the sulfur-in-fuel correlation used for SO_2.

The missing data procedures being proposed today would also provide a tiered system to promote high CEMS emissions data capture rates mandated by the Act and necessary for the proper functioning of the SO_2 allowance trading market and the NO_x emissions averaging provisions of the Acid Rain program.

The proposed rule would require affected units to calculate, on a daily basis, annual monitor availability (defined as a rolling percentage of total unit operating hours during the previous 365 days) for the SO_2 pollutant concentration monitor, the flow monitor, and the NO_x continuous emission monitoring system, and to substitute conservative estimates for missing data as a function of availability, length of missing data period, sulfur content range for SO_2, and load range for NO_x and flow. The monitor availability thresholds have been placed at levels that, according to the EPA and UARC studies cited previously, can be achieved by well-maintained monitors based on current technology. These studies indicate that the average annual availability during 1988-1990 of both SO_2 and NO_x monitors, at units subject to Subpart Da requirements was above 95 percent, and that over 90 percent of these monitors achieved an annual availability above 90 percent.

a. *SO_2 Concentration missing data procedures.* Under today's proposal, each affected unit would establish fuel sulfur content ranges based on a single fuel analysis every six hours which is correlated to the hourly CEMS values. EPA believes that this sampling frequency will yield a sufficiently accurate correlation between the CEMS emission rates and the actual sulfur content of the coal. These ranges would be established and used to ensure that neither significant overreporting or underreporting of emissions will occur due to the missing data routine. The 90th-percentile value would be calculated on a rolling daily basis for each of the previous 30 or 365 days for use in the missing data routine as described below. Whenever a missing data period occurred which required such a value, the operator would identify the sulfur-content range for the coal fired during that hour and select the 90th-percentile value from the appropriate range.

If annual SO_2 concentration monitor availability is greater than or equal to 95 percent, an estimate of probable actual emissions or flow consisting of the arithmetic average of the values for the hour immediately before and the hour immediately following the missing data period would be used to fill in missing data periods up to and including 24 hours.

If the missing data period exceeds 24 hours, but annual monitor availability is greater than or equal to 95 percent, the owner(s) and operator(s) would substitute for each hour in the missing data period the higher of the 90th-percentile hourly SO_2 concentration recorded by the monitor during the previous 30 days in the relevant sulfur-content range for the unit during the missing data period, or the average of the hour before and the hour after the missing data period, whichever is higher.[86]

Two reasons have prompted EPA to select 24 hours as the cutoff for using less conservative statistical estimation methods: (1) Various analyses, including UARG's, provide support for only very limited use of statistical methods, if at all, for filling in missing data periods over 24 hours; and (2) 24 hours, according to some utility representatives, corresponds to the time needed to transport, warm-up, and calibrate a portable CEMS as a replacement for a malfunctioning primary CEMS.

If annual monitor availability is less than 95 percent, but greater than or equal to 90 percent, the proposed rule provides a three-tiered system for filling in missing data where each tier is related to the length of the missing data period. As mentioned previously, the proposed methods for filling in missing data are intended to become more

[85] E26—Arizona Department of Environmental Quality, Comments on EPA Issue Papers, N. Wrona, February 15, 1991.

[86] Previous substitute data determined by a missing data routine would not be included for the purposes of determining the 90th-percentile hourly SO_2 concentration during any previous period.

conservative as the length of the missing data period increases.

Tier 1 would apply to missing data periods up to and including 6 hours, which represents over 75 percent of all missing data according to the UARG study. In this tier, EPA proposes to use an arithmetic average of the emissions values recorded for the hour immediately before and the hour immediately following the missing data period to fill in each hour of the missing data period.

Tier 2 would apply to missing data periods greater than 6 hours but less than or equal to 24 hours. In this tier, EPA proposes to use either the 90th-percentile hourly SO_2 concentration for the appropriate coal sulfur-content range recorded during the previous 30 days, or the average of the hour before and the hour after the missing data period, whichever is higher, to fill in each hour of the missing data period. Substitute data obtained by this procedure may be somewhat more conservative than the substitute data used in Tier 1, thereby providing an incentive for prompt repair of monitors when they malfunction.

Tier 3 would apply to missing data periods greater than 24 hours. In this tier, EPA proposes to use either the 90th-percentile hourly SO_2 concentration recorded by the monitor during the previous 365 days, or the average of the hour before and the hour after the missing data period, whichever is higher, to fill in each hour of the missing data period. EPA has selected this conservative procedure for filling in long missing data periods to discourage the incidence of such periods and to promote the use of a back-up, portable, certified CEMS as a replacement for a malfunctioning primary CEMS.

The Agency believes that this three-tiered approach strikes a balance between the goal of providing incentives for high monitor availability and the concern that overly conservative methods for filling in missing data might lead to capital expenditures for duplicate monitors by all (or most) affected units. Such expenditures may not be warranted in terms of expected incremental improvements in the accuracy of SO_2 emissions data, particularly for low-emitting and moderate-emitting units.

If annual monitor availability falls below 90 percent, the proposed rule would require the use of either the 90th-percentile hourly SO_2 concentration for the appropriate sulfur-content range recorded by the monitor during the previous 365 days of service, or the average of the hour before and the hour after the missing data period, whichever is higher, to fill in each hour of the missing data period. The Act requires EPA to declare a unit to be operating in an uncontrolled manner if substitute data satisfactory to the Administrator cannot be provided during missing data periods. EPA believes no satisfactory substitute data exists when annual monitor availability is less than 90 percent and, thus, is defining the 90th-percentile hourly value recorded over the preceding 365 days in the corresponding sulfur-content range as equivalent to uncontrolled emissions.

For affected units not equipped with add-on emission controls, the prescribed missing data procedures would be considered as "satisfactory to the Administrator" without any additional information. Under the proposed rule, affected units with add-on emission controls such as flue gas desulfurization (FGD) for SO_2 or selective catalytic reduction (SCR) for NO_x would monitor specified parameters to document the proper operation of their control equipment during missing data periods. The proposed rule specifies the required parameters for monitoring the pollution removal efficiency of different types of add-on emission controls. For example, affected units equipped with wet FGD control systems ("scrubbers") would be required to record and report the following information for each hour during all missing data periods: Number of scrubber modules in operation, percent solids in slurry, feedrate of makeup slurry, inline measure of absorber pH, and average pressure differential across each scrubber module. A national utility association representing many scrubbed units has indicated that it is reasonable to require the continuous monitoring of these emission control parameters during all missing data periods.[87]

Because affected units with add-on emission controls are likely to experience greater swings in emissions variability, EPA is proposing to allow these units to develop optional alternate procedures for filling in missing data based on parameter monitoring correlations. Under the proposed rule, such alternate procedures would be approved only on a site-specific basis and they could be used only to fill in missing data periods when annual monitor availability is greater than or equal to 90 percent. Prior to the approval of a site-specific parameter monitoring procedure for filling in missing data, affected units with add-on emission controls would be required to use the statistical estimation and other procedures prescribed in the proposed rule. EPA requests comment on these procedures, as well as comment on the question of whether there is a less complex way to achieve comparable results.

b. *Flow and NO_x* emissions missing data procedures. For flow and NO_x emissions, the proposed rule retains the structure of the missing data procedure used for SO_2, but incorporates modifications that address the differences between the types of emissions being considered. In the case of NO_x, since the relevant quantity is emission rate, the NO_x missing data routine, including availability calculations, is based on the combined system of NO_x monitor and diluent monitor, and all NO_x missing data substitutions are in terms of emission rate.

Beyond this difference, the physical fact that both flow and NO_x emissions are correlated with load dictated a number of differences between the specifics of the SO_2 missing data routine and the flow and NO_x missing data routines. For the latter two, the conservative values for missing data substitutions would be derived from correlations between load and flow, and between load and NO_x emission rate, based on the data recorded during specified periods during the previous service of the monitoring system.[88] These correlations would be determined using the load-based correlation procedure in paragraph 3 of appendix C of the rule. To support this correlation procedure, affected units would establish correlations with load analogous to the previously described sulfur-content correlations for SO_2. Affected units would record hourly load, which would then be divided into load ranges and correlated with the hourly CEMS values for NO_x and flow. This correlation would be established and used to ensure that neither significant overreporting or underreporting of emissions would occur due to the missing data routine. The 90th-percentile value would be calculated on a rolling daily basis for each of the previous 30 or 365 days for use in the missing data routine as described below. Whenever a missing data period occurred which

[87] "Missing Data Periods for Affected Coal-Fired Utility Units," Large Public Power Council, April 25, 1991.

[88] In developing this method, EPA considered the aforementioned UARG study presenting a correlation method for flow data, "Alternative Procedure for Estimating Volumetric Flow Rate." Technical Memorandum to UARG from Science Applications, Inc., 6/19/91. In EPA's judgment, both flow and NO_x emissions are sufficiently correlated with load to permit the use of correlation procedures like those described in this study.

required such a value, the operator would identify the load range during that hour and select the 90th-percentile value from the appropriate range. The specific substitution routines for each tier of the procedure are outlined below; note that the structure of the procedure (availability thresholds, etc.) exactly mirrors the structure of the SO_2 procedures.

If annual NO_x or flow monitor system availability is greater than or equal to 95 percent, and the missing data period is 24 hours or less, the owner(s) and operator(s) would substitute for each hour in the missing data period the average flow rate or NO_x emission rate recorded during the previous 365 days at the corresponding load range recorded for the missing hour.

If the missing data period exceeds 24 hours, but annual monitor availability is greater than or equal to 95 percent, the owner(s) and operator(s) would substitute for each hour in the missing data period the 90th-percentile recorded flow rate or NO_x emission rate during the previous 30 days at the corresponding load range recorded for the missing hour.

If annual monitor system availability is less than 95 percent, but greater than or equal to 90 percent, the proposed rule provides a three-tiered system for filling in missing data where each tier is related to the length of the missing data period. As mentioned previously, the proposed methods for filling in missing data become more conservative as the length of the missing data period increases.

Tier 1 would apply to missing data periods up to and including six hours. In this tier, EPA proposes to use the average recorded flow rate or NO_x emission rate during the previous 365 days at the corresponding load range recorded for the missing hour.

Tier 2 would apply to missing data periods greater than six hours but less than or equal to 24 hours. In this tier, EPA proposes to use the 90th-percentile recorded flow rate or NO_x emission rate during the previous 30 days at the corresponding load range recorded for the missing hour. Substitute data obtained by this procedure should be somewhat more conservative than the substitute data used in Tier 1, thereby providing an incentive for prompt repair of monitors when they malfunction.

Tier 3 would apply to missing data periods greater than 24 hours. In this tier, EPA proposes to use the 90th-percentile flow rate or NO_x emission rate during the previous 365 days at the corresponding load range recorded for the missing hour. EPA has selected this procedure for filling in long missing data periods to discourage the incidence of such periods and to promote the use of a back-up, portable, certified CEMS as a replacement for a malfunctioning primary CEMS.

As in the case of the SO_2 concentration missing data routine, the Agency believes that this three-tiered approach strikes an appropriate balance between the goal of providing incentives for high monitor availability and the concern that overly conservative methods for filling in missing data might lead to capital expenditures for duplicate monitors by all (or most) affected units. Such expenditures may not be warranted in terms of expected incremental improvements in the accuracy of flow and NO_x emissions data, particularly for low-emitting and moderate-emitting units.

If annual monitor availability falls below 90 percent, the proposed rule would require the use of the 90th-percentile flow rate or NO_x emission rate for the appropriate load range from the previous 365 days, as in Tier 3 above, except that here this maximum rate would be applied to all missing data periods. The Act requires EPA to declare a unit to be operating in an uncontrolled manner if substitute data satisfactory to the Administrator cannot be provided during missing data periods. EPA believes no satisfactory substitute data exists when annual monitor availability is less than 90 percent, and thus is defining the rate calculated by Tier 3 as equivalent to uncontrolled emissions.

G. CO_2 Emissions Monitoring

Section 821 of the Act states that EPA must require each unit subject to title IV of the Act to monitor and report annual emissions of CO_2. There are no CO_2 emission limits associated with the monitoring requirement. The emissions data are collected as a means of constructing a database that characterizes CO_2 emissions from electric utilities.

The Agency believes CO_2 emission data for affected units that generate such emissions only through fuel combustion can be obtained with sufficient accuracy for the purposes intended by either: (1) Monitoring the CO_2 concentration in the flue gas stream and calculating CO_2 emissions as the product of CO_2 concentration and measured flue gas flow rate, or (2) calculating daily CO_2 emissions based on the measured carbon content of the fuel through fuel sampling and analysis, and the annual amount of fuel combusted. Therefore, today's proposed rule provides the owner(s) and operator(s) of affected units that generate CO_2 emissions only through fuel combustion with the option of either: (1) Monitoring CO_2 emissions directly; or (2) using specified procedures and American Society for Testing and Materials (ASTM) methods to calculate CO_2 emissions based on the measured carbon content of the fuel and the amount of fuel combusted.

The Acid Rain Advisory Committee has indicated that either the continuous monitoring of CO_2 emissions or the computation of CO_2 emissions using specified procedures and the ASTM fuel sampling and analysis methods would satisfy the Act's CO_2 monitoring requirements. Some representatives of State agencies have commented, however, that they would prefer the Acid Rain CEMS regulation to be written so as to encourage (but not require) the use of CEMS with CO_2 (instead of O_2) as the diluent gas.[89] While EPA endorses the concept of encouraging the continuous emission monitoring of CO_2, others have noted that such a regulation would effectively eliminate approximately half of today's CEMS from the market. CEMS using O_2 are at least as accurate and reliable as those using CO_2. In fact, there has been a suggestion that O_2 can be monitored more accurately than CO_2, thereby providing better information on diluent gas concentrations.[90] Accordingly, EPA has rejected the recommendation of promoting the use of CO_2 diluent gas monitors in the Acid Rain CEMS regulation.

Affected units equipped with wet FGD or fluidized bed control systems generate CO_2 in the FGD process or in combustion using a fluidized bed system, and would therefore require additional accounting of CO_2 emissions. Based on suggestions from the Large Public Power Council and other industry groups, for these units today's proposal requires the owner(s) and operator(s) to (1) monitor the CO_2 concentration in the flue gas stream and calculate CO_2 emissions as the product of CO_2 concentration and measured flue gas flow rate, or (2) calculate daily CO_2 emissions based on the measured carbon content of the fuel through fuel sampling and analysis and the annual amount of fuel combusted, and on the amount of CO_2 generated in the desulfurization process. This latter amount can be calculated based upon

[89] E26—Comments on EPA Issue Papers, N. Wrona, Arizona Department of Environmental Quality, February 15, 1991.

[90] E14—Acid Rain Advisory Committee (ARAC) Emissions Monitoring Subcommittee Minutes, February 20, 1991.

the amount of SO_2 removed by the FGD or fluidized bed system.

H. Opacity Monitoring

Many of the units subject to today's proposed regulation already have continuous opacity monitors to comply with existing federal, State, or local opacity regulations.[91] These devices have been in service for a number of years and have performed reliably during that time. Because of this situation, the EPA is proposing that the opacity requirements for the Acid Rain program be the same as those under subpart Da (40 CFR 60.42 and 60.42(a)), with the exceptions outlined in the next paragraph. Also, under the proposed rule, the owner(s) and operator(s) would be required to submit reports of excess emissions of opacity to the applicable permitting authority.[92] EPA reasoned that this approach to reporting opacity data would result in the best coordination with preexisting air quality programs and the most efficient use of opacity data.[93]

Unlike emissions of SO_2 and NO_x, opacity is not directly related to the creation of acid rain. Moreover, EPA would like to mesh the acid rain program opacity monitoring requirements with those of pre-existing federal, State, and local air quality programs. EPA is therefore proposing to exempt from opacity monitoring gas-fired units that combust natural gas for no less than 90 percent of their total heat input during the year with oil as the back-up fuel. These gas-fired units have very low opacity levels,[94] and few of them are required to monitor for opacity under other federal, State, or local regulations. Nevertheless, where such requirements exist, this exception for title IV purposes has no effect on the units' need to comply with other provisions of the Act.

EPA is also proposing to exempt wet-scrubbed units from the opacity monitoring requirement, since it is often difficult to measure opacity after moisture is added to the flue gas by a wet scrubber. Under earlier programs such as the New Source Performance Standards (NSPS) program, units with a wet flue gas desulfurization system (wet "scrubber") were required to monitor opacity at the outlet of the scrubber if possible, and at the scrubber inlet if there were significant difficulties with measuring opacity due to moisture. Information from an opacity monitor at the inlet to a wet scrubber would not be useful to the Acid Rain program, although it would still be useful for other programs. Natural-gas-fired units and wet-scrubbed units would not be required to install opacity monitors to meet the requirements of part 75, but would still be required to meet any other federal, State, or local opacity monitoring requirements.

I. Recordkeeping and Reporting Requirements

Records and reports of continuous emission monitoring data and systems are required to provide the information necessary for assessing compliance with the Act's limitations on SO_2 and NO_x emissions and the proposed monitoring requirements. Such information also is needed by EPA for measuring progress towards the Act's goals of an annual 10 million ton SO_2 reduction and the mandated NO_x reduction and for developing reports to Congress on assessments and program evaluations of the changes in air quality, visibility, and acidic deposition effects resulting from the SO_2 and NO_x reductions.

The proposed rule includes requirements for: (1) Monitoring plans, which must be submitted to EPA not later than the date of submittal of the permit required by part 72, (2) written notifications of monitoring performance certification tests, (3) maintenance of records of emissions and flow, (4) reports of performance certification tests, (5) reports of quality assurance and quality control tests, and (6) quarterly reports of emissions, flow, unit operating status, and monitoring system performance data. The proposed requirements were derived from existing rules for utilities in 40 CFR part 60—subparts D, Da, Db, and Dc and modified to meet the needs of the Acid Rain program.

1. Monitoring Plan for Compliance Plan and Permit

Section 75.23(a) of the proposed rule requires that the designated representative submit a proposed Monitoring Plan to EPA for each affected unit at the source. A standard form would be required for this submission. The Monitoring Plan would be required to contain information on operating conditions, pollution control equipment, and unit configuration, and on the components of the monitoring systems, including the data acquisition and handling system. This information is necessary for EPA to evaluate the appropriateness of the source's monitoring plan, and would provide the basis for tracking and evaluating the quarterly emission data reports submitted by the affected units to EPA. EPA believes that submission of such information with the monitoring plan would eliminate duplicative submissions of identifying information with each quarterly report, and that permit amendments would be needed only for substantive changes to components or procedures. EPA also believes that such data would allow the Agency to perform analyses of continuous emission monitoring system performance by unit and monitoring system configurations. Such analyses would be used to assess improvements in monitoring technology and to provide information that could assist the regulated community in its selection of appropriate monitoring approaches. Using the form to obtain this information also would ensure that all information submitted is consistent and complete. The standardized format, moreover, should be convenient for sources and should minimize Agency review time. The proposed form is designed to facilitate computerization of the reported information.

2. Notification of Monitoring Performance Certification Tests

Written notification to EPA by the designated representative for the affected unit 30 days prior to conducting performance certification tests and periodic tests for quality assurance is required to provide EPA representatives the opportunity to attend the test. A similar notification requirement is included in the General Provisions to 40 CFR part 60. A notification required by other State or federal regulations that is substantially similar to that required in the proposed rules would satisfy the proposed notification requirement.

3. Recordkeeping and Reporting of Emissions and Flow Data

Under Subpart Da, sources are required to maintain detailed and complete records of pollutant concentration and opacity measurements (or approved surrogates for these) necessary to assure compliance with the applicable emission standards. However, EPA has required these sources to routinely report only that subset of the information necessary to determine compliance, to assist in regulatory development, or to assist in federal implementation of the Act's requirements. When reports indicate

[91] "Opacity" refers to the degree to which emissions reduce the transmittance of light and obscure visibility.

[92] "Excess emissions of opacity" refers to the measured opacity during any six-minute period, or other State-promulgated averaging period, when the applicable opacity limit is exceeded.

[93] "Opacity Monitoring Reports Required by Title IV," L. Paley and S. Viggiani, EPA, March 11, 1991.

[94] E-19, "Issue Paper—Continuous Emission Monitoring Exemption for Gas-Fired Utilities," Central and South West Services, submitted to the Acid Rain Advisory Committee (ARAC), March 1991.

potential noncompliance or supplemental information is needed to determine compliance, EPA can require the sources to submit additional information from records maintained at the facility. Access by others (States, the public) to the records maintained at the source is ensured by the Freedom of Information Act, subject to the requirements of "reasonableness" and the Paperwork Reduction Act.

The proposed rule would maintain this traditional relationship between the recordkeeping and reporting of CEMS data. EPA would require the routine recording and reporting of data needed to: (1) Assess compliance with program's emission reduction requirements; (2) certify the accuracy of measurements and substitute data; (3) allow for operation of the allowance trading market; (4) measure progress toward achievement of the Act's mandated annual reductions in SO_2 and NO_x; and (5) perform Congressionally mandated assessments and program evaluations of the changes in air quality, visibility, and acidic deposition effects resulting from the SO_2 and NO_x reductions.

During development of the proposed rule, there was a general recommendation by ARAC representatives that EPA apply the traditional relationship between recordkeeping and reporting of monitoring data to the Acid Rain program. ARAC representatives also made recommendations on the contents of records to be maintained at the source, particularly regarding the appropriate time period for emissions accounting.[95] EPA has considered differing views on the specificity of report contents and the question of the aforementioned accounting period. One view considered by EPA is that the reporting of hourly emissions data is integral to the Act's requirement "to provide on a continuous basis a permanent record of emissions and flow." [96] An overwhelming majority of the States with whom EPA has discussed recordkeeping and reporting issues already require the reporting of continuous emission monitoring data as hourly (or shorter) averages, and the few with daily averaging time periods believe hourly (or shorter) data would be more useful for assessing compliance.[97] Some utility representatives have said that while they had no objection to a requirement for sources to maintain records of hourly emissions data, they believe routine reports to EPA need not include emissions data more detailed than monthly or quarterly totals.[98] Various ARAC representatives, however, have told EPA that compliance with State regulations to report emissions data as hourly (instead of daily) averages has not been burdensome, and that they would favor standardization between Federal and State continuous emission monitoring programs.[99] State agency representatives have also endorsed the concept of reporting consistency between the Acid Rain program and State programs.

The proposed rule would require the reporting of hourly averages for the following types of emissions and flow data: (1) SO_2 and NO_x pollutant concentrations (ppmv); (2) exhaust gas volumetric flow rate (scfh); (3) stack moisture content, volume fraction, where SO_2 pollutant concentration measures are on a dry basis; (4) SO_2 mass emissions rate (lbs/hr); (5) fuel sulfur content (percent, as fired); and (6) NO_x emission rate (lbs/mmBtu). EPA also considered the need to collect SO_2 emissions data on a parts-per-million by volume (ppmv) basis in addition to pounds-per-hour data, which corresponds to the units of the standard (tons per year) for SO_2 under Title IV. EPA has determined that these data are necessary to check the correctness of the units' application of the missing data procedures in the proposed rule. Hourly SO_2 and NO_x emissions measures on a ppmv basis are also essential to the atmospheric modeling required for certain Congressionally mandated assessments and program evaluations.

EPA also believes that the routine reporting of hourly emissions and flow data to EPA would promote more cost-effective overall program implementation, yielding significant cost savings to the government. Some States have reported finding major computational and other software errors during audits.[100] Reporting of hourly data would allow EPA to use computer-based screening routines to "flag" incomplete records, inconsistencies, and indicators of potential compliance problems with the monitoring requirements which, in turn, would enable EPA to target its field auditing resources more effectively. Daily (or longer) accounting periods for the reported emissions and flow data would substantially complicate, or may even prohibit, using these rapid and inexpensive screening procedures. The proposed rule would require the reporting of hourly emissions and flow data in sufficient detail for EPA to identify the probable misapplication of missing data procedures or monitor out-of-control criteria without resorting to audits of the units' on-site records. It would also enable EPA to confirm, quickly and on a continuous basis, the accuracy of units' computational algorithms for combining SO_2 pollutant concentration, flow rate, and (where appropriate) stack moisture content measures into estimates of hourly SO_2 mass emissions (in lbs/hr).

For periods of missing data (i.e., when all or part of the continuous emission monitoring system is not functional or is operating outside the applicable performance specifications), the proposed rule would require the recording, on an hourly basis, and reporting of the method of emissions and/or flow determination. The proposed rule contains codes to assist owner(s) and operator(s) in specifying the method accurately and consistently. Units equipped with add-on SO_2 and/or NO_x emission controls also would be required to record, on an hourly basis during periods of missing data, information on the operation and effectiveness of their SO_2 and/or NO_x removal systems. This information, recorded during periods of missing continuous emission monitoring data, would also be reported to EPA.

Under the proposed rule, during each year from 1995 through 1999 units with a qualifying Phase I technology also would be required to record and report the average hourly SO_2 emission rate (lb/MMbtu) at the inlet (i.e., before the emission controls) and outlet. At year end, the owner(s) and operator(s) would report all measurements and calculations necessary to substantiate that the qualifying technology has achieved the required 90-percent reduction (on an annual-average basis) in SO_2 emissions pursuant to part 72.

In addition to emissions and flow data, the proposed regulation would require recording and reporting of the operating data for unit load and heat input. Unit load data are needed on an hourly basis for the load-based missing data procedure for NO_x emissions and flow. Heat input data are required to evaluate compliance with the reduced-utilization provisions of the Act, and to

[95] E22—Acid Rain Advisory Committee (ARAC) Emissions Monitoring Subcommittee Minutes, March 20, 1991.

[96] IID-54, memo by R. Poirot, State of Vermont Department of Environmental Conservation, March 12, 1991.

[97] IIA-104, State Agency Experience in Recordkeeping and Reporting, March 20, 1991.

[98] Issue Paper on Emissions Monitoring Under Title IV of the 1990 Clean Air Act Amendments, UARG, February 13, 1991.

[99] Acid Rain Advisory Committee (ARAC) Minutes, March 21, 1991.

[100] IIA-104, State Agency Experience in Recordkeeping and Reporting, 20 March 1991.

calculate penalties for NO_x emissions in excess of the standard. Collection of these data will require little additional effort: load information is routinely recorded by utilities, and the required heat input data can be calculated either from the available flow and diluent gas emission data or from oil flow meter and oil sampling/analysis data. Heat input from natural gas would be determined by analysis of each shipment received.

In addition to these hourly data, affected units also would be required to record daily and report the following information: (1) Percent monitor availability for the SO_2 pollutant concentration monitor, the flow monitor, and the NO_x continuous emission monitoring system; (2) results of daily calibration error tests (percent error and number of out-of-control hours) for the SO_2 pollutant concentration monitor, the flow monitor, the NO_x continuous emission monitoring system, and the CO_2 monitor (if used); (3) F-factor value used to convert NO_x concentration to units of the standard (lbs/mmBtu); and (4) total CO_2 emissions (tons/day). Under the proposed rule, the owner(s) and operator(s) also would record hourly and report the unit (boiler) operating time, gross operating load, and heat input (mmBtu). These data are needed for computing percent monitor availability, a critical factor in the proposed missing data procedures, and for determining whether reduced utilization as defined in part 72 has occurred.

4. Availability and Maintenance of Records

EPA is proposing to allow the Agency and permit authorities to perform periodic inspections of records and equipment to ensure compliance because records of information not otherwise reported are needed for regulatory authorities to evaluate inspection findings. If EPA elected not to require records for inspection at the source, it would result in an inadequate mechanism for verifying compliance and would not be consistent with the statutory requirement for "a permanent record of emissions and flow."

In addition to the emissions and flow data specified previously to be recorded and reported, the proposed rule would require the owner(s) and operator(s) to maintain records containing hourly averages for the following data on each affected unit: (1) Stack gas temperature (°F), and (2) stack gas exit velocity (ft/sec). These data are needed to confirm the representativeness of average gas flow rates measured by the flow monitor. Hourly diluent monitor readings used to calculate NO_x emission rates would also be required. The owner(s) and operator(s) would also be required to maintain records of adjustments, maintenance, and corrective actions performed on pollutant concentration and diluent gas monitors, flow monitors, moisture monitors (if applicable), and the data acquisition and handling system. Such records are already required by subpart Da as well as many State programs. The proposed rule would require that the records be maintained in a form suitable for inspection at the source for at least two years, which is consistent with subpart Da.

5. Reports of Performance Certification Tests

Reports of performance certification tests would be required under the proposed rule for initial certification or recertification of the continuous emission monitoring systems, the continuous opacity monitoring system, and any approved alternative monitoring systems. These reports are needed by EPA to determine that the monitoring and data acquisition and handling system equipment required by the proposed rule meet the applicable installation, design, and performance specifications. This reporting requirement is consistent with requirements included in existing reporting requirements for utilities subject to NSPS.

6. Reports of Quality Assurance and Quality Control Tests

The proposed rule would require reports of quarterly and annual quality assurance and quality control tests for the continuous emissions monitoring systems, any approved alternative monitoring systems, and the continuous opacity monitoring system. These reports are needed by EPA to confirm that: (1) Emissions and flow data are quality assured, and (2) the missing data procedures and monitor out-of-control criteria in the proposed rule are being applied properly. They are also needed for EPA to evaluate, on an ongoing basis, whether accuracy standards established for the pollutant concentration monitors, the flow monitors, and the continuous emission monitoring systems reflect current technology. This reporting requirement is included in existing reporting requirements for utilities subject to NSPS.

7. Quarterly Reports

EPA is proposing quarterly submissions of monitoring data. In selecting the proposed standards, EPA also considered more frequent reporting, such as real-time telemetry or daily reporting. However, reports submitted by affected units must be screened for accuracy and completeness prior to entry into the EPA databases, and therefore such reporting was rejected as impractical, particularly during the startup years of the program. Less frequent reporting, such as annual submissions, would not provide EPA with the necessary information to identify a potential problem at the source within a reasonable timeframe. Annual submissions were also rejected because of the administrative difficulty and costs of processing, quality assuring, and assessing an entire year's worth of data for hundreds of affected units in Phase I and thousands of affected units in Phase II.

Quarterly reports of emission data for SO_2, NO_x, volumetric flow, CO_2, and other information are required for EPA to assess compliance with the proposed monitoring requirements and with other provisions of the Acid Rain program. Quarterly reporting provides the needed information within a timeframe that allows EPA to manage and assess the information in a timely manner. Such reporting also is consistent with other current Federal and State requirements. For these reasons, quarterly reporting was selected for the proposed rule.

8. Electronic Reports

The heart of the title IV program, the allowance trading program, will be an electronic system in order to maintain timely and accurate records of allowance holdings and trades available to all trading participants. EPA intends to enter monitoring data into databases using the same computer facilities as for the trading information. In addition, many utilities are already experienced in electronic reporting of monitoring data through various State programs, such as those in Pennsylvania and Illinois. The concept of electronic reporting for this proposed rule also has been endorsed by the Acid Rain Advisory Committee, which believes that this type of reporting will reduce burden, minimize errors, and ensure the viability of the "true-up" period for end-of-year allowance and emission balancing. EPA believes that electronic reporting is also the most practical way to implement the program for the utilities as well as EPA. Nevertheless, EPA requests comment on whether electronic reporting should be required, or whether other reporting formats should also be allowed.

The proposed rule would require the owner(s) and operator(s) to electronically report the required

information as an ASCII flat file via either an IBM-compatible personal computer floppy diskette or by a modem. To facilitate electronic reporting for all affected units, EPA plans to develop a guidance document containing user-friendly information on electronic format and standardized forms. This document will be available for distribution shortly after the promulgation of the Acid Rain CEMS regulation.

9. Reporting Party

Consistent with the provisions of 40 CFR part 72, the proposed rule specifies that the designated representative will be responsible for submitting quarterly reports of recorded emissions and flow data and reports on the performance of Phase I qualifying technologies on behalf of the owner(s) and operator(s). The owner(s) and operator(s), however, would be responsible for the more technical certification and periodic quality assurance tests of the continuous emission monitoring system and its components. EPA requests comment as to whether all reports should be the responsibility of a single person, namely the designated representative, even though this individual may not be knowledgeable of site-specific conditions and continuous emission monitoring instrumentation.

J. Alternative Monitoring Systems

In general, the Act requires affected units to install and operate continuous emission monitoring systems for monitoring SO_2 and NO_x emitted into the atmosphere. However, it also allows units to use an alternative monitoring system for monitoring one or both of these emissions, or a component of such emissions (e.g., SO_2 concentration, flow), provided that EPA can certify that the data produced by the alternative monitoring system is equivalent to that from a CEMS on four criteria: Precision, reliability, accessibility, and timeliness. EPA defines the applicable criteria as follows: (1) Precision—the closeness of the emissions measurements (or indirect determinations of emissions) to the true emissions; (2) reliability—the ability to operate within the prescribed performance specifications and quality assurance standards without interruptions in operation for a specified number of hours each year; (3) accessibility—the ability to generate the required data in the form needed to meet recordkeeping and reporting requirements; and (4) timeliness—the ability to record and issue the required data within a stipulated time period. To preserve the orderly functioning of the allowance system and to ensure that the mandated emissions reductions are achieved, the Act also gives EPA the authority to set limitations on the use of alternative compliance methods by units equipped with alternative monitoring systems.

1. Demonstrations of Equivalency to CEMS

Under the proposed rule, EPA would use the performance of certified SO_2 pollutant concentration monitors, flow monitors, and NO_x continuous emission monitoring systems, defined in the previous sections, as benchmarks for approving or rejecting proposals for alternative monitoring systems. Thus, to qualify under the precision criterion, the difference between measurements from an alternative monitoring system for measuring SO_2 concentration or flow and a certified SO_2 pollution concentration or flow monitor would be required to fall within defined statistical limits. Three statistical tests would be used for this comparison: (1) A T-test to assess the systematic error; (2) an F-test to assess the random error; and (3) a correlation analysis, supported by time-series plots, to determine how well the proposed alternative monitoring system tracks the CEMS benchmark measurements over time. The same approach would be used for evaluating an alternative monitoring system for measuring NO_x emissions on the precision criterion, except that the benchmark would be a certified NO_x continuous emission monitoring system.

Similarly, to meet the reliability criterion, the alternative system would be required to match or surpass the appropriate certified benchmark in terms of annual availability and ability to meet performance specifications and quality assurance requirements. In order to satisfy the accessibility and timeliness criteria, an alternative system would be required to match the capabilities of the CEMS in being able to record the requisite monitoring data on an hourly basis and to report results within 24 hours.

Monitoring systems proposed as alternatives to CEMS will be reviewed on a case-by-case basis by EPA according to the criteria and evaluation procedures summarized above and detailed in § 75.21 of the regulation. Approval will be contingent on the applicant's providing substantial, long-term statistical evidence that the precision, reliability, accessibility, and timeliness offered by the proposed alternative is equivalent or superior to CEMS.

EPA believes that these requirements will permit affected units to implement alternative monitoring systems where they are justified. In addition, by using CEMS as a benchmark for judging alternative systems, the proposed rule would establish a framework in which technological innovations offered by alternative systems could establish improved and more cost-effective emission monitoring standards in the future.

2. Proposed Exceptions for SO_2 CEMS: Gas-Fired Units and Oil-Fired Units

Under the proposed rule, EPA would offer two prescribed excepted monitoring methods for estimating SO_2 mass emissions per unit time as an alternative to CEMS for gas-fired and oil-fired units. Gas-fired units that combust natural gas for no less than 90 percent of their total heat input during the year with oil as the backup fuel would be allowed to use an excepted method due to the good performance of that method with respect to the four aforementioned criteria (precision, reliability, accessibility, and timeliness), and to the de minimis nature of the SO_2 emissions from this category of affected units. In addition, units which combust oil, diesel fuel, or any combination of oil, diesel fuel, and gas, would be allowed to use an excepted monitoring method for determining SO_2 mass emissions due to the relative homogeneity of oil with respect to sulfur content, the effectiveness of the method in obtaining representative samples, and the resulting good performance of the method with respect to the aforementioned criteria.

In the case of the gas-fired units that combust natural gas for no less than 90 percent of their total heat input during the year with oil as the backup fuel, according to EPA's National Allowance Database the 525 existing units of this type emitted only 7600 tons of SO_2 in 1985, yielding a unit average of less than 15 tons annually.[101] In addition, only six of the 525 units emitted more than 100 tons in 1985. Under the proposed excepted monitoring method for these units, there would be no requirement to continuously monitor SO_2 emissions when the unit is combusting natural gas. Based upon the typical amount of sulfur found in natural gas measured by ASTM methods for analysis, these units will emit less than 100 kg of SO_2 annually while combusting natural gas.[102]

[101] E24—Baseline Tons of SO_2 (1985) for Selected Categories of Affected Units Under Title IV, Acid Rain Advisory Committee (ARAC).

[102] ASTM D3031, "Standard Test Method for Total Sulfur in Natural Gas."

Representatives from utilities, State agencies, and environmental groups concur with EPA's assessment that such emissions would be non-existent or negligible.[103] When the unit is combusting oil, either in-line oil flow meters would be required to continuously monitor the amount of oil consumed, or the highest value from a series of daily composite samples would be used to monitor the sulfur content of that oil and estimate SO_2 mass emissions (in lbs) hourly.

Representatives of the gas-fired utility industry have provided EPA with a case study which proposes that, for gas/oil-fired units combusting no less that 90 percent natural gas, in-line oil flow meters and oil sampling procedures can provide a level of precision and reliability close to a continuous emission monitoring system.[104] These case studies indicate that using specified ASTM procedures for oil sampling and analysis, the proposed excepted monitoring method for SO_2 emissions meets the random error criteria (discussed previously) for precision. Although no data are available on the long-term reliability of the proposed method, these studies imply there would be little or no data loss when the proposed oil flow monitoring and oil sampling procedures are used for ten days a year, which would be the typical usage for these units.[105]

For gas/oil units using less than 90 percent gas in their combustion mix, or for units firing exclusively oil or diesel fuel, a second excepted monitoring method is proposed as an alternative to CEMS. This exception is based on the relative ease of obtaining representative samples of these fuels, and on the fact that fluid fuels, such as natural gas or oil, are much more homogeneous in sulfur content than coal. Preliminary data comparing oil sampling and analysis and CEMS values implied that these two methods track each other.[106] Data from oil sampling and analysis protocol consistently produce higher emission rates than the CEMS data. Accordingly, EPA proposes that units firing oil, natural gas, diesel fuel, or a combination of these may use the more precise of the proposed excepted procedures in appendix D of part 75. EPA expects more conclusive data soon to be available upon the completion of a demonstration of several emission monitoring methods for SO_2 from consumption of oil by Consolidated Edison of New York.

The proposed monitoring methods have three main features: Accurate metering of oil flow, as-fired oil sampling, and procedures specified by ASTM for the analysis of oil for sulfur content and density. EPA chose to limit the accuracy of fuel flow meters to +/− 2 percent to ensure accurate and precise emissions data from the entire process after fuel flow data and oil sampling and analysis errors would also be combined. EPA also considered selecting an accuracy of +/− 1 percent for oil flow meters, since several types of meters can meet this requirement.[107] However, the Agency noticed that the looser 2 percent accuracy specification would allow all of the commonly used flow meter types, including some of the less expensive flow meters, without greatly affecting the overall accuracy of the process. As suggested by the gas-fired utility industry, EPA would require oil flow meters to be calibrated annually.[108]

For this approved excepted method, EPA is proposing an oil sampling protocol based on ASTM methods that is most likely to provide precise, accurate data. The Agency had some concern that the variability of sulfur in oil over the course of a day might allow an underestimation of emissions if oil samples were taken only once daily. This would be especially likely in cases where an operator purchases individual shipments of oil at the lowest price. In such cases, the sulfur content of the oil could vary significantly within one day as the unit began to burn the new supply of oil. In order to ensure that oil samples are truly representative of the amount of sulfur in combusted oil, EPA is proposing automatic sampling on an hourly basis in proportion to the rate of oil flow for units firing more than 10 percent oil. In addition, daily manual oil samples are allowed for gas-fired units. Since a single, manual daily sample might be lower in sulfur content than the average for the entire day, an operator taking daily oil samples would be required to use the highest sulfur content of the previous 30 daily samples to prevent underestimation.

There are many different methods for analyzing oil for density and sulfur content. EPA chose a variety of ASTM methods for analysis of oil in order to allow the greatest flexibility. The flexibility afforded by these provisions would allow in-house utility laboratories or outside laboratories to analyze oil using either manual or automated methods.

The proposed excepted monitoring method would provide hourly SO_2 emissions data by the following day, thus achieving the same accessibility and timeliness as for CEMS.[109] Industry representatives have suggested that this "next day" turn-around time requirement may sometimes be impractical for units located in remote areas and for units that must send out oil samples for analysis. Other timeliness requirements, ranging from three to nine days, have been suggested. Further comment is solicited on this point.

EPA has received a proposal for additional procedures to determine SO_2 emissions from oil-fired units from members of the oil-fired utility industry.[110] These sets of procedures require oil-fired units to use an oil flow meter but allow the flexibility of less precise, less continuous samples in exchange for using a default value for fuel sulfur content which will yield conservatively high emission estimates. A continuous method of oil sampling such as frequent automated sampling or continuous drip sampling would be expected to be as precise as a continuous emission monitoring system. A single, manual daily oil sample might be less representative than a continuous sample; thus, an operator taking daily oil samples would use the highest sulfur content measured in the past 30 days to calculate emissions of SO_2 to prevent underestimation. EPA has considered this procedure and has proposed its use for gas-fired units. The additional flexibility of allowing manual sampling would be especially useful for this class of units which fire oil for a short period of time each year, since they would not need to purchase special sampling equipment for use only during a few days each year. EPA solicits comment regarding the appropriateness of this monitoring method, and regarding the

[103] E22—Acid Rain Advisory Committee (ARAC) Emissions Monitoring Subcommittee Minutes, March 21, 1991.

[104] Presentation materials on continuous emission monitors for gas/oil units <10% oil, submitted to ARAC Emissions Monitoring Subcommittee, J.R. Smith, Houston Lighting and Power Co., April 25, 1991.

[105] Data from Barney Davis Plant, Central Power and Light.

[106] "Preliminary Analysis of Oil Sampling and Analysis and Continuous Emission Monitoring," Kilkelly Environmental Associates, July 15, 1991.

[107] Table 6–1, Chapter 6, Flow Measurement Engineering Handbook, R.W. Miller.

[108] Presentation materials on continuous emission monitors for gas/oil units <10% oil, J.R. Smith, Houston Lighting and Power Co., submitted to the Acid Rain Advisory Committee (ARAC) Emissions Monitoring Subcommittee, April 25, 1991.

[109] This would be equivalent to a daily calibration error test.

[110] "Class of '85, Proposed Alternative Emissions Monitoring System for Oil and Gas Fired Affected Units," June 6, 1991.

possibility of extending it to diesel- and other oil-fired units. In addition to these two procedures, the Class of '85 proposal also includes the option of using the maximum permitted oil sulfur content as a default sulfur value at all times for units with such a permit limitation. Gas-fired units and oil-fired units operating for 400 hours a year or less would be able to monitor the changes in sulfur content and mass of oil in storage, rather than monitoring and sampling the fuel as it is about to be burned. EPA has considered these options but has concerns about their administration, as well as the clear departure from the statutory requirements for monitoring methods with the same precision, reliability, accessibility, and timeliness as CEMS.

EPA has reviewed and rejected proposals for alternatives to CEMS for the monitoring of NO_x emissions by gas-fired units combusting no less than 90 percent natural gas annually. These units may have non-negligible NO_x emissions and are not exempted from the NO_x continuous emission monitoring requirements of this part. Further, EPA has identified no alternative monitoring system for NO_x emissions that even closely approximates a CEMS on the criteria required by the Act. The proposed alternative monitoring methods for NO_x would provide data that would not be quality assured until the next year when a test would be conducted. This clearly does not meet the requirement for timeliness of data. EPA also has received no alternative NO_x monitoring data comparing readings from a proposed protocol with those from a NO_x CEMS.

VII. Excess Emissions Regulation

A. Background and Purpose

Part 77 of today's proposal sets forth the requirements for excess emissions offset planning and offset penalties, pursuant to section 411 of the Clean Air Act, as amended (the Act). As a general rule title IV of the Act is intended to provide maximum flexibility for sources to determine the means by which they would comply with the sulfur dioxide and nitrogen oxides emissions limitations of the Acid Rain program. However, Congress deemed the statutory goal of reducing acid deposition precursors as paramount.

Section 411 eliminates any financial benefit owners and operators of affected sources might otherwise derive from exceeding their emissions limitations, by imposing an automatically due and payable statutory penalty for each ton of excess sulfur dioxide or nitrogen oxides emissions emitted by an affected unit in a calendar year. (See, section 411 (a) and (c)).

These penalties are in addition to penalty liability any source risks under other enforcement provisions of the Act (Section 411(e)). In addition, the Administrator is required to deduct sulfur dioxide allowances to the extent an affected unit has experienced excess emissions of sulfur dioxide in any calendar year. (See, section 411(b)). (This obligation is in addition to other allowance deductions that would be required for, e.g., violations of Phase I Extension plan's provisions under section 404(d)(7), or the reduced utilization planning provisions.)

Finally, Congress underscored the severity with which it viewed violations of Acid Rain program requirements, including excess emissions, by providing specifically that nothing in section 411 limits or affects the liability that a source might have under the Act's other enforcement authorities, including section 113 which authorizes the imposition of civil and criminal sanctions for violations of the Act. (See, section 411(e)).

Given the degree of flexibility otherwise afforded sources under title IV, the Agency proposes to ensure strict compliance by affected sources with the emissions reduction requirements of the Acid Rain program, and the excess emissions offset and penalty requirements of section 411 of the Act. Consistent with the program generally, however, the proposal does afford flexible excess emissions offset planning opportunities for sources.

Today's proposal includes several provisions intended to ensure the deterrent effect of these sanctions. These are discussed in greater detail below, but a few deserve special mention. With regard to excess emissions penalties, EPA proposes to encourage compliance with the automatic nature of the penalty obligation by including an interest adjustment as part of the penalty to account for any delays in payment. Other provisions that would ensure the deterrent effect of the program include the provisions in 40 CFR parts 77 and 72, imposing liability on multiple-owners, operators, and the designated representative of a violating unit, and on all owners, operators, and designated representatives of affected units governed by an approved multi-unit compliance plan. These provisions lend a self-monitoring element to the program that is critical to ensuring compliance.

EPA considered whether to require offset plans for excess emissions of nitrogen oxides. This proposal does not require nitrogen oxides offsets because they are not specifically required by section 411 and there is no allowance system that would enable ease of accounting for such offsets. Sources violating the nitrogen oxides emissions reduction requirements of the Acid Rain program would, however, be subject to the full array of enforcement authorities under the Act, including the authority of the Agency to issue appropriate remedial orders necessary to protect the environment and deter future violations.

The proposed rule is organized as follows: Section 77.0 describes to whom the requirements of 40 CFR part 77 apply. Section 77.1 defines terms used in 40 CFR part 77. Section 77.2 specifies the sulfur dioxide excess emissions offset planning requirements of this part. Section 77.3 describes the actions the Administrator will take on proposed offset plans. Section 77.4 and appendix B of this part specify requirements for the imposition, calculation, and payment of excess emissions penalties. Sources would be obligated to calculate penalties in accordance with a specified formula. In addition, as required by the Act, the rule provides that each year EPA will publish adjustments to the statutory base penalty amount of $2,000 per ton for inflation using the Consumer Price Index. The rule specifies the formula EPA will use to calculate the adjusted penalty. The rule provides, consistent with section 411 of the Act that penalties would be required to be paid to the U.S. Treasury, without demand, and that interest would be required to be paid on tardy payments. Section 77.5 specifies the proposed requirements for the submission of information, including signatory requirements, and cites the relevant Federal and State authorities, as well as the recordkeeping requirements.

B. Applicability

Section 77.0(a) explains that the requirements of this part would apply to owners, operators, and designated representatives of affected units under the Acid Rain program. This is consistent with the statutory provisions which specify that these persons are responsible for ensuring compliance with the emissions reduction obligations of the program.

Section 77.0(b) restates the savings clause found in 40 CFR part 72 and other parts of today's proposal, providing that whenever a requirement or prohibition in 40 CFR parts 70–78 was worded as applying to an affected source or an affected unit, or to the designated representative of an affected source or unit, it would also apply to each owner

and operator of the affected source or unit. This is a fundamental liability concept underlying the Acid Rain program, which underscores the owners', operators', and designated representatives' shared responsibility and liability for ensuring that violations are remedied. Thus, while the designated representative is the primary point of contact with EPA on the holding and transfer of allowances, permitting, and compliance reporting in the Acid Rain program, owners and operators are not immunized by this relationship, and are equally liable for ensuring compliance with the requirements of the program by the affected source or unit. The designated representative serves a specialized fiduciary role (e.g., a special category of operator) essential to the program's inherent flexibility. Owners and operators, however, remain primarily responsible for ensuring compliance with the Act's requirements. This liability is provided for in section 411 and elsewhere in title IV of the Act. (See, for further discussion, the 40 CFR part 72 preamble and rule.)

Consistent with section 411(e) of the Act, § 77.0(c) states that nothing in 40 CFR part 77 would limit or otherwise affect the enforcement and investigatory authorities contained in sections 112(r)(9), 113, 114, 120, 303, 304, or 306 of the Act. These include administrative enforcement, and a variety of civil and criminal judicial enforcement authorities. Section 411 of the Act specifies the strict liability under the program that results from excess sulfur dioxide and nitrogen oxides emissions. The liability is automatic and requires no enforcement action. Section 77.0(c) of the proposed rule would, thus, codify the statutory savings clause that, notwithstanding the obligations and remedies of 40 CFR part 77, violators risk further enforcement for excess emissions pursuant to the full range of investigatory and enforcement authorities of the Act. The remedies available under sections 112(r)(9), 113, 114, 120, 303, and 306, of the Act are, moreover, not to be diminished in any way by any remedy available under 40 CFR part 77.

C. Definitions

Section 77.1 provides that, for 40 CFR part 77, the terms would have the same meaning as that given in the Act, in 40 CFR parts 72–78, and in § 77.1 of the rule, as listed. Language incorporating the definitions of the other Acid Rain program regulations and the Act, by reference, appears in each part of the program rules, and is intended to assist in preserving the program's integrity. The terms defined in § 77.1 of today's proposal specifically are those central to a clear understanding of 40 CFR part 77. One definition deserves special mention. The term "ton" is defined as including any ton or fraction of a ton of emissions. This is particularly necessary with regard to sulfur dioxide emissions since fractions of allowances are not provided for in the program. In addition, it is more protective of the environment, ensures maximum deterrence of violations, and obviates any disputes regarding the total tons of offsets that must be achieved.

D. Sulfur Dioxide Excess Emissions Offset Planning

Section 77.2 sets forth the requirements related to sulfur dioxide excess emissions offset planning. Section 411(b) provides that for each ton of sulfur dioxide emissions in excess of an affected unit's Acid Rain program sulfur dioxide emissions limitation (i.e., the allowances held for use by the unit for the calendar year in the unit's Allowance Tracking System compliance subaccount), the unit must offset the excess emissions with allowances. Today's proposal requires that the offsets be achieved by a deduction of one allowance from the affected unit's Allowance Tracking System account established pursuant to 40 CFR part 73 for each excess ton of emissions. Section 411(b) also provides that the allowances must be offset in the year following the year when the excess emissions occurred, unless the Administrator approves a longer offset period. Accordingly today's proposal specifies that, unless the designated representative for the unit submits an approvable excess emissions offset plan providing otherwise, allowances would be deducted by the Administrator from the allowances contained in the affected unit's Allowance Tracking System compliance subaccount account for the year in which excess emissions occurred.

Conceptually, excess emissions offset plans are treated in 40 CFR part 77 as similar to a 40 CFR part 72 compliance plan. Thus, an approval by the Administrator of an offset plan would revise the previously approved permit for the affected source. An excess emissions offset plan would have to be submitted to EPA by the designated representative of the affected unit that had emissions in any calendar year in excess of its sulfur dioxide emissions limitation (i.e., the allowances held for use by the unit for the calendar year, in the unit's Allowance Tracking System compliance subaccount). The plan would have to specify a methodology for offsetting the excess emissions in as expeditious a manner as practicable.

Section 77.2(a) provides that any affected unit that emits sulfur dioxide in any calendar year in excess of its sulfur dioxide emissions limitation for that year, would be required to compensate for those excess emissions during the offset period approved by the Administrator, by an amount of not less than the tons of excess emissions that occurred during that year. Section 77.2(a) would require that the sulfur dioxide emissions limitation would be determined each year based on the number of allowances held in the affected unit's Allowance Tracking System compliance subaccount, as provided in 40 CFR part 73 of today's proposal.[111] Section 77.2(a) also restates the requirement set forth in section 411(b) of the Act that, for each ton of sulfur dioxide emissions in excess of an affected unit's emissions limitation, the Administrator is required to deduct one allowance from the affected unit's Allowance Tracking System account (unless another unit is designated to provide the offsets) (See, further discussion below.)

Section 77.2(b) restates the statutory mandate that, within 60 days after the end of the calendar year in which excess emissions occurred at an affected unit, the designated representative would have to submit a proposed excess emissions offset plan to the Administrator. The rule proposes that the plan be sent to EPA Headquarters, to the Region for the State where the affected unit is located, and to the State in which the affected unit is located. The requirement to provide permitting States with copies of excess emissions offset plans is proposed to help close coordination since these plans, once approved, would amend the permit. In addition, the requirement to copy both EPA Headquarters and the appropriate EPA Regional Office is included to avoid delay, and to provide flexibility for the Agency and maximum convenience for the affected source during the process of responding to excess emissions situations. (See, discussion of "team approach" in preamble for 40 CFR part 72.)

Section 77.2(e) would require that the plan describe the measures proposed to

[111] It should be noted that Title IV provides a default in the event the Acid Rain Program allowance system were to fail. The Act provides that, in the absence of an allowance program, each unit's sulfur dioxide emissions limitation is the tonnage equivalent of the allowance allocations for the unit pursuant to sections 404 and 405 of the Act. 40 CFR part 77 has been worded to accommodate any such default.

be taken by the source to offset the excess emissions, including:

• The number of offset allowances required to be deducted from the Allowance Tracking System account of the unit or units providing the offsets; and

• A schedule, with appropriate increments of progress: for reducing sulfur dioxide emissions and deducting the offset allowances from the Allowance Tracking System account for the unit or units responsible under the plan; for achieving the offsets, including specification of the identification numbers of the allowances to be deducted and specification of when they should be deducted; for obtaining additional allowances necessary to ensure continuous compliance; and for taking corrective actions.

• The serial number of the allowance deductions (if the designated representative elects to specify the deductions) using the Compliance Deduction Form as provided for in 40 CFR part 73.

Additionally, § 77.2(e)(5)(ii) would require, consistent with 40 CFR part 73, that each sulfur dioxide excess emissions offset plan include a certification that no allowances would be transferred during the offset period from the Allowance Tracking System account for any unit responsible for the required offsets that are needed for offsetting the excess emissions or that might cause any further excess emissions of sulfur dioxide at the unit.

Section 77.2(c) proposes that, except as discussed below, separate excess emissions offset plans would be required to be submitted for each affected unit with excess emissions. Since each affected unit would be subject to, and would be required to be operated in compliance with, the sulfur dioxide emissions limitations of the program, each affected unit is viewed as a separate entity relative to excess emissions. Even where one representative is designated for two or more affected units, the rule would provide that each affected unit with excess emissions would be subject to a separate excess emissions offset planning requirement.

Section 77.2(d) proposes that the one exception to the separate excess emissions offset planning requirement would be units governed by a multi-unit compliance plan approved pursuant to 40 CFR part 72, subpart D. These include substitution plans, reduced utilization compensating unit plans, Phase I Extension control unit plans, and plans for units with a common stack monitor. The basis for this exception is that units operating under a multi-unit compliance option would have interdependent compliance obligations.

For example, units operating under a common stack plan are constrained by an inability to differentiate emissions between or among those units monitored at the common stack. In view of this problem, the Agency has proposed in 40 CFR part 75 to treat units that share a common stack monitor as one unit for purposes of calculating emissions unless a demonstration is made certifying separate monitors for each unit. In addition, 40 CFR part 72 proposes that such units would be governed by a common-stack plan. Consistent with this approach the Agency believes it is appropriate and necessary to require one excess emissions offset plan from the combination of units that are governed by a common stack plan. Thus, if the combined emissions exceed the aggregate allowances held for the units governed by the common stack plan, all of the units whose emissions were monitored at the common stack would have to be treated as being in noncompliance. Moreover, since units with emissions ducted through and monitored at a common stack cannot be assigned separate emissions limitations, all the owners and operators of all the units using the common stack would be liable for the excess emissions.

Similarly, in the case of units operating under any other multi-unit compliance plan, the duty to offset exceedances of the sulfur dioxide emissions limitations as provided by the plan at any one unit would have to be shared by all the units governed by the plan. Otherwise, since an individual unit's ability to comply depends on operations at the other units under the plan, defenses to excess emissions offset planning requirements could be raised based on disputes concerning the actions by the other interdependent units. Under a substitution plan, for example, an excess emissions situation could be the result of disputes between majority and minority owners concerning the transfer of allowance allocations from the substitution unit's Allowance Tracking System account to the originally affected unit's account. Such disputes cannot be allowed to delay the excess emissions offset planning obligation. By making each owner and operator of a unit governed by a multi-unit plan liable for the offset planning obligation, this section would build into the program a self-regulating element that should minimize, if not totally eliminate, such problems.

Section 77.2(e) specifies the excess emissions offset plan content requirements. Section 77.2(e) would require that each proposed excess emissions offset plan be submitted on the standard form proposed in appendix A of 40 CFR part 77. The information required by the standard form would ensure that essential information identifying the designated representative for the affected unit with excess emissions and information about each affected unit is included in the plan. The submission would also have to be signed by the designated representative for each unit governed by the plan. These requirements would be consistent with the general approach for Acid Rain program submissions proposed in 40 CFR parts 72, 73, and 75 and are intended to minimize the burden on sources making submissions, and increase the Agency's ability to rely on each submission as being fully authorized by the source.

Such plan would have to include certifications concerning the extent of excess emissions, including a description of how and why the excess emissions occurred, and of any corrective actions that were taken to prevent or minimize the extent of excess emissions. This information would assist the Agency in evaluating the adequacy of a proposed excess emissions offset plan including the source's ability to prevent excess emissions in the future.

The rule would also require that each excess emissions offset plan include a description of the measures that would be taken to offset the exceedance and a schedule with increments of progress for achieving the offsets. This description is required even if the unit's plan entails only buying extra allowances on the open market to cover the amount of the unit's emissions. The plan would have to include a demonstration that the schedule results in offsets as expeditiously as practicable, taking into account electric reliability. EPA solicits comment on appropriate criteria for evaluating electric reliability. One criteria the Agency is considering is system reserve margin.

Section 77.2(e) also addresses proposed excess emissions offset plans that rely on one or more of the Acid Rain compliance options authorized under 40 CFR part 72, subpart D (e.g., reduced utilization and substitution plans). If the designated representative wanted to propose to offset excess emissions occurring during any year by relying on a compliance option authorized under subpart D of 40 CFR part 72, the excess emissions offset plan would have to include the appropriate standard form required by 40 CFR part 72 for the compliance option chosen. If the compliance option chosen involved multiple units, the plan would have to

designate any compensating or substitution unit, and a schedule for achieving the required offsets in coordination with the designated unit. For example, the schedule should specify deadlines for reducing utilization of the unit responsible for the excess emissions and for shifting load to a compensating unit. Finally, a certificate of representation establishing the authority of the designated representative(s) with regard to all the units covered by the multi-unit plan would have to accompany the proposal to ensure accountability. The rule specifies that any plan relying on an Acid Rain compliance option of 40 CFR part 72, subpart D, would have to result in reductions equal to those that would be required by a standard excess emissions offset plan providing for allowance deductions directly from the Allowance Tracking System account for the affected unit responsible for the excess emissions.

Section 77.2(e) also proposes that, if the designated representative seeks to offset excess emissions by installing a technological means of pollution control, the excess emissions offset plan would have to specify increments of progress for installing and commencing operation of the equipment, and include a showing of technological adequacy. This would be essential information for a source to be able to demonstrate that the offsets would be achieved as expeditiously as practicable.

Section 77.2(e) would also require that the excess emissions offset plan list and describe the provisions of the affected unit's permit and approved compliance plan that would be revised by the proposed excess emissions offset plan, if approved. In order to determine the merits of an excess emissions offset plan, it is necessary that the Administrator and other interested persons be able to understand where and how the permit and approved compliance plan would be changed. This information would serve to ensure that proposed changes to the permit and compliance plan by the excess emissions offset plan do not yield unanticipated results.

The rule would also require that the excess emissions offset plan include a schedule for the submission of progress reports. Quarterly progress reports, due in accordance with the quarterly reporting schedule of § 72.401(b), would be required from the designated representative, beginning with the calendar quarter (April 30 of each year) following the date on which an excess emissions offset plan is due, and concluding in the quarter in which the offsets are achieved. The Agency considered whether reporting should be driven by the increments but determined that a standard reporting approach would add to ease of administration and ensure consistent treatment of sources. These reports would be required to include a description of the work accomplished; a demonstration that interim milestones were achieved; a summary of remaining work to be performed; and proposed adjustments, if any, to the schedule.

In addition, a final report and supporting documentation would be required, to be included in the annual report required by 40 CFR part 72, within 30 days after the end of the year during which the offsets were achieved in full. The final report would include a description of the work performed in accordance with the excess emissions offset plan, the date that the offsets were achieved, and the number of tons of offsets achieved. To ensure that each designated representative submitting a report under this section is fully aware of the liability for false submissions, § 77.2(e) would also require that each report be signed and contain the standard certification regarding the truth and accuracy of submittals that would be required under 40 CFR part 72. This is necessary so the Agency can accept the submission as reliable.

E. Administrator's Actions on Offset Plans

Section 77.3 specifies the procedures for EPA action on proposed excess emissions offset plans and the effect of such plans and Administrator actions. Subsections (a) through (c) would require the Administrator to review each proposed excess emissions offset plan for administrative and substantive completeness and issue a determination of completeness to the affected source within 30 days of receipt, similar to proposed § 72.72. Thereafter, the Administrator would be required to act on a proposed excess emissions offset plan within 6 months of its receipt. This again tracks the 40 CFR part 72 procedures. Subsection (d) specifies the steps the Administrator would take to propose an offset plan.

Subsections (e) through (h) would provide an opportunity for public comment on an excess emissions offset plan. It is intended that such public comment opportunity would be afforded by the Administrator, following procedures similar to those that would be required by 40 CFR part 72, subpart J, § 72.301 (permit modification procedures), before the Administrator would take action on a proposed excess emissions offset plan. The opportunity for public comment is being proposed since the excess emissions offset plan would, on approval, alter the requirements applicable to an affected source under the approved operating permit during the offset period, and would revise any inconsistent permit provisions.

Once approved, an excess emissions offset plan would be incorporated into the permit as an administrative amendment under § 72.303 of today's proposal. (See, further discussion below regarding § 77.3(l)). This is appropriate since an opportunity for public review and comment on the proposed excess emissions offset plan would have already been afforded by the Administrator under 40 CFR part 77. It would, therefore, be redundant to afford an additional opportunity for public comment under 40 CFR part 72. However, it is important that interested States and anyone who commented on the original permit receive notice of the excess emissions offset plan as approved. The administrative amendments procedure of 40 CFR part 72 would afford such notice.

Subsections 77.3 (i) through (j) describe how the Administrator could approve the excess emissions offset plan as submitted, in whole or in part with appropriate revisions, or conditionally with expeditious deadlines for the conditions to be met not later than the end of the year. Otherwise, the Administrator could disapprove the plan, and deduct allowances or issue such order as is necessary to achieve the offsets. In taking any such action, the Administrator would have to specify an excess emissions offset period for achieving the emissions reductions in full.

Section 77.3(k) would require the Administrator to deduct allowances, in accordance with the approved excess emissions offset plan, equal to the tons of excess emissions. Section 77.3(k) restates the requirement in section 411(b) of the Act that the allowances must be deducted in the year immediately following the year when the excess emissions occurred, unless the Administrator approves a longer offset period. Accordingly, § 77.3(k) would require that, in the absence of an approvable excess emissions offset plan, allowances be deducted from the affected unit's Allowance Tracking System account beginning with the unit's compliance subaccount. This subaccount contains only those allowances currently usable by the unit (If allowances in the compliance subaccount are insufficient, allowances

would be deducted from future year subaccounts.)

The rule would also authorize that allowance deductions be spread-out over a specified period greater than one year. However, this would require a showing by the affected source, to the Administrator's satisfaction, that deducting the entire amount of the allowances required to offset the excess emissions during the following calendar year would interfere with electric reliability. It should be understood that a high hurdle is intended and that such a showing would be extremely difficult to make. This is particularly so in the case of sulfur dioxide since the affected source would have to also demonstrate that allowances were not available on the market. The overriding concern sought to be addressed by this limitation is the need to ensure expeditious offsets, consistent with the annual reduction program contemplated by the statute. Moreover, the Agency wants to avoid protracted remedies since they would tend to compound compliance problems.

Today's rule, however, proposes to authorize excess emissions offset plans that rely on one or more of the Acid Rain compliance options specified in 40 CFR part 72, subpart D of today's proposal, as a method of freeing-up or generating the allowances that would be required to be deducted to offset the excess. (See, § 77.2(e).) Accordingly, pursuant to an approved excess emissions offset plan, the allowances could be deducted from a compensating or substitution unit's Allowance Tracking System account.

Section 77.3(l) provides that, upon a determination of completeness, the proposed excess emissions offset plan would be binding on the designated representative and the owners and operators of the unit(s) governed by the plan, and would presumptively revise any inconsistent provisions of the permit and approved compliance plan for the affected source. The proposed offset plan would remain in effect until the Administrator acted on the proposal as provided in § 77.3(i). This approach is proposed to be consistent with 40 CFR part 72 and to ensure expeditious action by the source toward achieving the offsets and that, at any given time, there is maximum possible certainty regarding what requirements apply to an affected source. However, total clarity would not be achieved until the offset plan is approved following public comment.

Following approval of an excess emissions offset plan by the Administrator, § 77.3(l) also provides that the excess emissions offset plan would be deemed to be incorporated into the permit without further review or revision as an administrative amendment under proposed § 72.303. It should be noted that, since approval of the excess emissions offset plan would amend the permit, the Administrator's action on the plan would be a permitting decision. Such action would, thus, be subject to the permit appeals provisions of subpart H of 40 CFR part 72 and section 307 of the Act.

Subsections 77.3 (m) and (n) provide that it is a violation of the Act and this part: For a designated representative of an affected unit with excess emissions to fail to submit a complete and approvable proposed excess emissions offset plan or any progress reports required by 40 CFR part 77, in a timely manner; for a unit to fail to comply with the terms of a proposed or approved excess emissions offset plan; or for anyone subject to 40 CFR part 77 to fail to offset excess emissions as required by that part. Any such failure would be a separately enforceable violation of the Act. Additionally, § 77.3(o) provides that each day of delay after the 60-day deadline for submitting excess emissions offset plans, or after a reporting deadline, would be deemed a separately enforceable violation of the Act. These provisions are intended to create certainty and to put the regulated community on notice of the high price that would be paid by not complying strictly with the program's requirements.

F. Excess Emissions Penalties

Section 77.4 and appendix B of today's proposal specify the requirements that would apply for the imposition, calculation, and payment of excess emissions penalties. Consistent with section 411(a) of the Act, § 77.4(a) would require that the designated representative of an affected unit which had excess emissions of sulfur dioxide or nitrogen oxides in any calendar year submit payment of the excess emissions penalty without demand. (The method for calculating tonnage emissions of nitrogen oxides will be specified in 40 CFR part 76.)

Section 77.4(a) also provides that the designated representative and the owners and operators of the affected unit with excess emissions would be held strictly liable for the obligation to automatically pay, without delay, any penalty due under this part.

The proposal restates the statutory mandate in section 411(a) that excess emissions penalties are due automatically (i.e., January 1 of the year following any excess emissions) and are subject to the Miscellaneous Receipts Act. However, the rule proposes that payments of excess emissions penalties owed would have to be paid no later than the deadline for submitting the excess emissions offset plan, (i.e., no later than 60 days after the end of the calendar year in which excess emissions occurred at an affected unit.) Although this would extend the date for payment of the penalty, it would afford affected sources a reasonable period of time to conform their allowance accounts with end-of-year allowance purchases, as is proposed in 40 CFR part 73.[112] (See, discussion below regarding the § 77.3(c) interest obligation.) Thus, not later than the allowance transfer deadline, an affected unit with excess emissions (i.e., an affected unit that was not able to conform its account as of the allowance transfer deadline), would either pay the excess emissions penalty plus interest or be deemed out of compliance with the penalty payment obligation. In this regard, affected sources relying on the allowance transfer deadline would do so at their own risk. Thus, with regard to penalties for excess emissions, the allowance transfer deadline does not affect the underlying statutory obligation and provides only a conditional reprieve from the absolute statutory obligation to pay excess emissions penalties automatically. (In the event of over-payment of penalties, the over-payment will be reimbursed pursuant to U.S. Treasury procedures.)

Section 77.4(b) states that the designated representative responsible for submitting the penalty is also responsible for correctly calculating that penalty. Affected sources would, thus, be obligated to correctly calculate penalties in accordance with a proposed formula. Section 77.4(b)(2) specifies the formula to determine the excess emissions penalty. The formula specifies that in October of each year, EPA will publish the adjusted excess emissions penalty, based on the excess emissions Consumer Price Index (CPI) penalty adjustment rate (EEPAR), calculated pursuant to appendix B of this part, and multiplied by the statutory base penalty rate of $2,000. The designated representative would be required to multiply the adjusted excess emissions base penalty by the number of tons of excess emissions (Q) to derive the excess emissions penalty (EEP): $EEP = ((EEPAR \times \$2{,}000) \times Q)$. The statutory base-penalty CPI adjustment is mandated by section 411(c), and ensures that excess emissions penalties remain a strong disincentive to avoided or

[112] The rule, thus, distinguishes the deadline when penalties are "due" and the deadline when "penalties due" are "payable", to integrate the automatic nature of the penalty obligation with the proposal in 40 CFR part 73 allow for the 30-day grace period for end-of-year allowance transactions.

delayed compliance. In this way pollution control would remain a cheaper option than noncompliance. Consistent with the 40 CFR part 73 CPI adjustment for allowance auctions and sales, and, as provided in appendix B, EPA proposes to publish the Consumer Price Index (CPI) adjusted excess emissions base penalty by October 15 of each year of the program (beginning in 1995). This will help ensure against disputes. EPA seeks comment on the CPI-adjusted penalty rate formula in appendix B.

The CPI can also be obtained by:

1. Contacting the Consumer Price Index Branch at (202) 523–1121; or

2. From the following publications:

a. Consumer Price Index Detailed Report;

b. Monthly Labor Review;

3. The publications listed in paragraph (b) are available from the:

a. Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402, or

b. Bureau of Labor Statistics, Publication Sales Center, P.O. Box 2145, Chicago, Illinois 60690.

Because the statute requires that excess emissions penalties are due automatically and payable without demand immediately after the end of the previous calendar year (See, § 77.4(a)), the rule also proposes that the penalty include interest, accruing beginning on January 1 of the year following the year the excess emissions occurred until the penalty is paid. (See, § 77.4(c).) This is consistent with other statutory authorities obligating the payment of moneys to the U.S. Treasury in accordance with the Miscellaneous Receipts Act. (See, e.g., 28 U.S.C. 1961.) In addition, an interest requirement would encourage compliance with the automatic nature of the penalty obligation, and be a clear disincentive for delays. The interest adjustment is in addition to the annual consumer price index adjustment to the statutory base penalty required by the statute and to any other penalty liability an affected source might incur for violations of the Act.

The Agency is proposing that interest on the excess emissions penalties accrue beginning January 1 of the calendar year following the year to which the penalties apply for the following reason. Despite the proposal of a 30-day period for completion of prior year allowance transfers, the penalty is accrued for the calendar year ending December 31. If a source is able to obtain allowances in January to cover excess emissions from the prior year, then no penalty, and thus no interest will accrue. However, if the source is unable to purchase such allowances in January, the penalty for the prior year should become due January 1, and thus failure to pay such penalty on that date should result in interest being assessed from that point on. In other words, the proposed 30-day compliance transfer deadline would not change the statutory obligation to comply for the "calendar year", rather, any allowances obtained by a source before the compliance transfer deadline will be deemed to have been held by the source for the previous "calendar year". Thus a source that has excess emissions in the prior calendar year, and makes no effort to purchase allowances to cover those emissions in January would not escape 30-days of interest accrued.

Alternatively, the interest on excess emission penalties could accrue beginning at the allowance transfer deadline. EPA solicits comment on its proposal to assess interest on excess emission penalties beginning January 1.

Section 77.4(c)(1) proposes that the interest rate be calculated based on the coupon issue yield equivalent of the 52-week U.S. Treasury bills average accepted auction price as determined by the Secretary of the Treasury, since this is a good indicator of the economic benefit a source might derive from delaying payment of the penalty.

Section 77.4(c)(2) provides the formula for determining the total penalty, with accrued interest (EEP_i). The formula specifies that the EEP_i is equal to the excess emissions penalty "(EEP)", as calculated pursuant to § 77.4(b)(2) (discussed above), multiplied by the sum of the interest rate "(i)", as calculated pursuant to § 77.4(c)(1), plus one (1). Therefore, the formula to derive the total penalty with accrued interest, (EEP_i), is: $EEP_i = EEP x (1 + i)^n$.

Section 77.4(d) would require that any penalty be due and payable automatically without demand, and specifies how penalty payments would have to be made. The rule also provides, consistent with section 411, that penalties are required to be submitted to the Administrator payable to the "U.S. Treasury", subject to the Miscellaneous Receipts Act. Payments of penalties less than $25,000 would have to be by cashier's or certified check, made payable to the "U.S. Treasurer", and sent to the appropriate lock box for the EPA Regional Office for the State where the affected unit is located. The amount of interest on such penalties would be calculated based on the month the check is received at the lock box. The Agency is currently considering whether to require that the penalty payment be sent to a central lock box, with copies of the submission sent to the Regions. This will be clarified in the final rule, with lock box addresses to be specified in appendix C to 40 CFR part 77. Payments of penalties of $25,000 or more would have to be made by wire transfer to the "U.S. Treasury" at the Federal Reserve Bank of New York. This is a standard procedure which banks are familiar with for paying obligations owing to the U.S. Government. A written confirmation of payment would be required to be sent to EPA. The amount of interest on penalties of $25,000 or more would be based on the month the check is received by the U.S. Treasury. Any affected source failing to pay the penalty in this manner would do so at its own risk.

Section 77.4(e) provides that it would be a violation of the Act for the designated representative of an affected unit, liable for penalty payments under this part, to fail to correctly determine the penalty amount, or to pay the penalty, as required by this part. Section 77.4(f) provides that any such failure would be deemed a separately enforceable violation of the Act, as would be any other failure to comply with the requirements of 40 CFR part 77.

Section 77.4(g) restates the savings clause of section 411(e), providing that any excess emissions penalty due under 40 CFR part 77 would not affect the liability of the affected unit's designated representative, owners, and operators for any additional fine, penalty or assessment for the same violation authorized under any other section of the Act.

Section 77.4(h) provides that the obligation to pay such penalties is subject to the limitation in section 411 concerning orders issued under section 110(f) of the Act. However, only orders issued during the year in which the excess emissions occurred would be excused.

G. Other

Section 77.5 specifies other relevant requirements for today's proposal, including the addresses for submissions, reservations of Federal and State authorities, signatory requirements, recordkeeping, availability of information, and computation of time. These proposed requirements are consistent with those included in part 72 of today's proposal. The reader is referred to the part 72 preamble of today's proposal for a discussion of these proposed requirements.

VIII. Impact Analyses

A. Executive Order 12291

Under Executive Order 12291, the Administrator must judge whether a regulation is "major" and therefore subject to the requirement to conduct a Regulatory Impact Analysis (RIA). This proposed rule package is "major" as defined in 1(b) of E.O. 12291 because the annual effect on the economy will be greater than $100 million. While the annual effect on the economy will be greater than $100 million, EPA does not anticipate major increases in prices, costs, or other significant adverse effects on competition, investment, productivity, or innovation or on the ability of United States enterprises to compete with foreign enterprises in domestic or foreign markets due to the proposed regulations.

Title IV, on its own without any implementing regulations, mandates extensive emission reductions and imposes continuous emission monitoring requirements on all sources. The reductions basically impose a reduction in emissions equal to the limit of allocated "basic" allowances. Such a program costs much more than the program assuming the allowance trading program, which provides for flexible, cost-effective compliance, the permits program, which provides for special compliance options such as the Phase I technology reserve program, and the monitoring program, which allows sources to implement alternative monitoring systems if they are demonstrated to match or exceed CEM systems.

A high base case and a low base case scenario were used in the analysis. These two cases were used by EPA to estimate the impacts of the legislation during the debate in Congress.

EPA's RIA evaluates the effects of a set of three regulations termed the "implementation regulations." These regulations are: Permit regulation; the Allowance System regulation, including tracking, transfers, auctions and sales, and conservation and renewable energy; and the continuous emissions monitoring regulation. Collectively, this set of implementation regulations establishes and implements the core of the acid rain program. NO_x control costs were not included in this analysis.

EPA estimated the costs of achieving the reductions in SO_2 emissions under the statute and the implementation regulations for the time period from 1993 through 2010. While the total costs will be much lower in Phase I than Phase II, this analysis annualized the costs over the entire 18-year period. The statute without the implementation regulations (absent regulations case) imposes substantial costs, with the total annualized costs ranging from $1.6 to $2.5 billion per year. The costs of the implementation regulations (regulatory case), with total annualized costs ranging from $0.9 to $1.5 billion, are substantially less than the costs of the statute absent the implementation regulations. Thus, to achieve the mandated SO_2 emission reductions, the implementation regulations result in annual cost savings of between $0.7 and $1 billion compared to the statute absent the regulations.

While these costs are large in absolute terms, they are relatively small compared to the $200 billion average annual costs of generating electricity. The annualized costs of the implementation regulations are estimated to increase the annual costs of generating electricity by 0.5 to 1.2 percent.

For permitting under the regulatory case, program participants will incur administrative costs to obtain permits. The administrative cost for affected sources to obtain permits is estimated to be $0.5 million per year for Phase I (1995–1999) and $5.4 million per year for Phase II (2000–2010). Under the absent regulations case, no permitting would take place, so there would be no costs associated with permits.

In the regulatory case, EPA estimates that the total impact for participants in the allowance trading market will range between $15 and $30 million per year. This estimate includes market evaluation and transactions costs. These costs are based on the assumption that transactions costs will average 1.5 percent of the value of trades, which is assumed to range between $1 and $2 billion annually. In the absent regulations case, no trading would occur, so there would be no transaction costs in that case.

Although the auction and direct sale regulations are not included in this rulemaking, the costs are presented here for completeness. The total estimated annual costs to auction participants are minor, ranging from $13,600 to $81,300. The estimated total costs for direct sale applicants is $13,500 over 2 years. Assuming all IPP guarantee applications occur in the first year, the total cost to IPP guarantee applicants is estimated to be $225,000.

The conservation and renewable energy reserve is an optional program intended to provide additional incentive for utilities to conduct conservation programs. Affected sources that choose to participate in this program are likely to do so because it is economically beneficial. Under the regulatory case, the cost to affected sources that choose to participate associated with obtaining allowances from the conservation and renewable energy reserve is estimated to be $100,000 to $200,000 per year. These costs include the burden to assemble and submit an application to EPA each year in order to receive allowances from the reserve. Under the absent regulations case, no conservation and renewable energy reserve would be established.

For monitoring, the costs to the regulated community under the absent regulations case include costs associated with the installation and maintenance of continuous emissions monitors (CEMs), continuous opacity monitors (COMs), and flow monitoring systems, if they do not already have one in place. No alternative monitoring methods would be allowed and no data reporting costs would be incurred. In this case the estimated cost to the regulated community is $173 million annually.

The analysis considered five monitoring options under the regulatory case. All five options include operation and maintenance requirements. Option 1 presents the most stringent regulatory case and has an estimated annualized cost to electric utilities of $225 million dollars. Option 2 permits the use of alternative monitoring methods and is estimated to cost $209 million annually. Option 3 exempts retiring plants from all monitoring requirements and has an estimated annualized cost of $220 million. Option 4 requires the use of standardized data reporting and recordkeeping requirements and is estimated to cost $221 million annually. Finally, EPA's proposed option, Option 5 combines all of the other regulatory options and has an estimated annualized cost of $203 million.

In both the absent regulation and regulatory cases the will yield environmental benefits due to the 10 million ton reduction in SO_2 below 1980 levels. The reductions will result in less acid rain and sulfate exposure, and better visibility and local air quality. The implementation regulations are expected to generate additional long run benefits by creating incentives for the development of improved pollution control technology.

The analysis is contained in the Regulatory Impact Analysis (RIA) of the Proposed Acid Rain Regulations, June 1991, EPA, Office of Atmospheric and Indoor Air Programs.

This proposed rule and RIA were submitted to the Office of Management

and Budget (OMB) for review prior to publication as required by E.O. 12291.

B. Regulatory Flexibility Act

The Regulatory Flexibility Act of 1980 requires each Federal agency to perform a Regulatory Flexibility Analysis for all rules that are likely to have a "significant impact on a substantial number of small entities."

For the purposes of this analysis, EPA used the Small Business Administration definition that a small electric power utility is one that generates a total of less than 4 billion kilowatt-hours per year. Not all small utilities are affected by the acid rain Title of the Act. Utilities will be unaffected if all of their units are: (1) Exempt (e.g., units use non-fossil sources of energy or simple gas turbines), or (2) below statutory minimums for electric generating capacity (e.g., generate less than 25 megawatts).

To examine the effects on small entities, EPA constructed six model small utilities of varying fuel type and size to represent most of the small utility population. Costs of SO_2 reductions are the incremental costs of acid rain controls, relative to the pre-statute case, under the absent regulations and regulatory cases. The implementation regulations lead to cost savings (or no change) relative to the absent regulations case for each model utility. However, even after the reductions in cost provided by the implementation regulations, the impacts on some small coal- and oil-fired utilities are still significant. In the worst case, the regulatory cost to these utilities could represent between 6 to 7 percent of the average value of electricity produced in the year 2000. About 36, or one-third, of the 105 affected small utilities could face impacts of up to this magnitude. The other two-thirds have regulatory impacts that are comparable to or less than the impacts on all utilities as a group.

EPA's analysis concludes that virtually all of the impacts on small entities are caused by statutory provisions of the Act. Although EPA is considering regulations that are intended to mitigate some of the burden on small businesses, the statutory provisions restrict the amount of relief that can be given. The implementation regulations are likely to result in substantial reductions in the costs imposed by the statute on small entities. As a percentage of the costs under the absent regulations case, the savings provided by the regulations may be similar to the savings for larger utilities. Therefore, by implementing these regulations, EPA has provided all the relief available under the statute to help the most affected small utilities. Based on this analysis and pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that this attached rule, if promulgated, will not have a significant economic impact on a substantial number of small entities.

C. Paperwork Reduction Act

The information collection requirements in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* An Information Collection Request document has been prepared by EPA (ICR No. 1584) and a copy may be obtained from Sandy Farmer, Information Policy Branch; EPA; 401 M St., SW. (PM-223Y); Washington, DC 20460 or by calling (202) 260-2740.

The total public reporting burden for these regulations is estimated to range between 66,000 and 73,000 hours in 1993; 33,000 and 40,000 hours in 1994; and 32,000 and 40,000 hours in the first five months of 1995. In order to obtain a permit, the public reporting burden to develop a permit application and compliance plan including certification of a designated representative is estimated to average a total of 370 hours per application. For tracking and transferring allowances, the public reporting burden to complete and submit an allowance tracking system new account form (if necessary) and an allowance transfer form is estimated to average 30 hours and 1 hour respectively. The burden for assembling and submitting an application to obtain allowances from the conservation and renewable energy reserve is estimated to average 80 hours per application. Finally, to meet the emissions monitoring requirements, the public reporting burden is estimated to average 40 hours per report per plant for preparing and submitting quarterly emissions data reports, and 15 hours per plant for submitting a one time monitoring plan. These burden estimates include time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing the collection of information.

Send comments regarding these burden estimates or any other aspect of this collection of information, including suggestions for reducing this burden, to Chief, Information Policy Branch; U.S. Environmental Protection Agency; 401 M St., SW. (PM-223Y); Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 726 Jackson Place NW., Washington, DC 20503, marked "Attention: Desk Officer for EPA." The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

IX. Supporting Information

List of Subjects in 40 CFR Parts 72, 73, 75, and 77

Air pollution control, Electric utilities, Sulfur dioxide, Nitrogen oxides, Continuous Emissions Monitors, Permits, Compliance Plans, Reporting and recordkeeping requirements.

Dated: October 29, 1991.

William K. Reilly,

Administrator, U.S. Environmental Protection Agency.

For the reasons set forth in the preamble, parts 72, 75, and 77 are proposed to be added and part 73, proposed at 56 FR 23744 (May 23, 1991), is proposed to be amended by redesignating subpart D as subpart E and adding subparts A-D and subpart F to chapter I of title 40 of the CFR to read as follows:

[**Note:** References to parts not included in this document will be published in the **Federal Register** at a future date.]

PART 72—PERMITS REGULATION

Subpart A—Acid Rain Permit Program General Provisions

Sec.
72.1 Purpose and scope.
72.2 Definitions.
72.3 Measurements, abbreviations, and acronyms.
72.4 Addresses for submissions.
72.5 Federal authority.
72.6 State authority.
72.7 Applicability.
72.8 Prohibitions.
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72.11 Availability of information.
72.12 Computation of time.
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Subpart B—Designated Representative—Certification Procedure

72.20 Certificate of representation.
72.21 Duties of the designated representative.
72.22 Changing the designated representative.
72.23 Objections.
72.24 Change owners and operators.
72.25 Designated representative identification number.

Subpart C—Acid Rain Permit Applications and Compliance Plans

72.30 Requirement to apply.
72.31 Information requirements for acid rain permit applications.

Authority: 42 U.S.C. 7651.

Subpart A—Acid Rain Permit Program General Provisions

§ 72.1 Purpose and scope.

(a) *Purpose.* The purpose of this part is to establish the operating permit program requirements for affected sources under the Acid Rain program, pursuant to section 408 of title IV of the Clean Air Act, 42 U.S.C. 7401, et seq. as amended by Public Law 101–549 (November 15, 1990) (the Act).

(b) *Scope.* The regulations under this part set forth requirements for obtaining three types of Acid Rain permits, during Phases I and II, for which an applicable source may apply: Acid Rain permits issued by the United States Environmental Protection Agency (EPA) during Phase I; the Acid Rain portion of a 40 CFR part 70 permit issued by a State or local permitting authority during Phase II; and the Acid Rain portion of a 40 CFR part 71 permit issued by EPA when it is the permitting authority during Phase II, as a result of a State not receiving approval of a permitting program under 40 CFR part 70, or the permitting authority not adequately administering or enforcing a 40 CFR part 70 program. These regulations include requirements for the processing of Acid Rain permit applications and compliance plans; certifying designated representatives; issuing and revising Acid Rain permits; appealing permits; and certifying compliance with the Acid Rain permit. The requirements of this part and 40 CFR parts 73–78 apply to affected sources under the Acid Rain program in the forty-eight contiguous States and the District of Columbia.

(c) *State and Local Permit Programs.* Certain requirements set forth in this part and 40 CFR parts 73–78, as noted herein, shall be applicable to the permitting of affected sources during Phase II of the Acid Rain program under State and local operating permit programs approved pursuant to 40 CFR part 70, or under permitting by EPA pursuant to 40 CFR part 71 in the absence of an approved State permit program under 40 CFR part 70. The Acid Rain permit requirements of this part supplement and in some cases modify the 40 CFR part 70 requirements for approving and implementing State operating permit programs pursuant to title V of the Act, and for Federal permits under 40 CFR part 71, as they apply to affected sources under the Acid Rain program.

(d) *Authority.* This part is implemented pursuant to the Clean Air Act, 42 U.S.C. 7401, et seq. as amended by Public Law 101–549 (November 15, 1990), including:

(1) Section 408(a) of the Act, which provides that the provisions of this title (title IV) shall be implemented, subject to section 403 (Allowance program), by permits issued to units subject to this title (and enforced) in accordance with the provisions of title V, as modified by this title.

(2) Section 502(a) of the Act, which provides in part that it shall be unlawful for any person to violate any requirement of a permit issued under this title, or to operate an affected source (as provided in title IV of the Act) except in compliance with a permit

issued by a permitting authority under this title.

(3) Section 506(b) of the Act, which provides that the provisions of this title * * * shall apply to permits implementing the requirements of title IV except as modified by that title.

(4) Section 403 of the Act, concerning the Acid Rain allowance program;

(5) Section 407 of the Act, concerning nitrogen oxides compliance options;

(6) Section 409 of the Act, concerning repowering extensions;

(7) Section 114 of the Act, which contains EPA's investigatory authorities; and

(8) Section 113 of the Act, which contains EPA's general enforcement authority.

§ 72.2 Definitions.

The terms used in this part shall have the meaning given in the Act as interpreted by this part and 40 CFR parts 73–78, and in this section, as follows:

Acid Rain compliance option means one of the following methods of compliance used by an affected unit under this part as described in a compliance plan submitted and approved in accordance with subpart D of this part:

(1) Standard sulfur dioxide compliance method: having total emissions in any calendar year that are not greater than the allowances held, as of the allowance transfer deadline, in the unit's compliance subaccount for that year in accordance with a plan submitted and approved under § 72.40(b);

(2) Standard nitrogen oxides compliance method: emitting nitrogen oxides from an affected unit during a calendar year in an amount not greater than allowed by the applicable emissions limitation for the unit, pursuant to 40 CFR part 76, in accordance with a plan submitted and approved under § 72.40(b);

(3) Compliance with a substitution plan submitted and approved in accordance with § 72.41;

(4) Compliance with a Phase I extension plan submitted and approved in accordance with § 72.42;

(5) Compliance with a reduced utilization plan submitted and approved in accordance with § 72.43;

(6) Compliance with a repowering extension plan submitted and approved in accordance with § 72.44;

(7) Compliance with a new unit plan submitted and approved in accordance with § 72.45;

(8) Compliance with a nitrogen oxides emissions averaging plan submitted and approved in accordance with § 72.46;

(9) Compliance with a nitrogen oxides alternative emissions limitation plan submitted and approved in accordance with § 72.47;

(10) Compliance with a nitrogen oxides compliance deadline extension plan submitted and approved in accordance with § 72.48;

(11) Compliance with an opt-in plan submitted and approved in accordance with § 72.49; or

(12) Compliance with a common-stack plan submitted and approved in accordance with § 72.50.

Acid Rain permit or *permit* means the legally binding written document issued by a permitting authority under this part (following an opportunity for appeal pursuant to subpart H of this part or a State administrative appeals procedure), including any revisions made thereto pursuant to subpart J of this part, specifying the Acid Rain program requirements applicable to an affected source, to each affected unit at an affected source, and to the owners, operators and designated representative of the affected source or the affected unit.

Acid Rain permit application means a request for an Acid Rain permit or renewal of such permit, and the information submitted by the designated representative of an affected source on EPA Acid Rain permit application forms (as provided in 40 CFR part 72, appendix C), which forms may be amended, revised, or modified from time to time. The term Acid Rain permit application shall include the proposed compliance plan for each affected unit, which plan shall be deemed incorporated into the Acid Rain permit application by reference by operation of law.

Acid Rain program means the sulfur dioxide and nitrogen oxides air pollution control program established pursuant to title IV of the Act under 40 CFR parts 72–78.

Act means the Clean Air Act, 42 U.S.C. 7401, et seq., as amended by Public Law No. 101–549 (November 15, 1990).

Actual 1985 emissions rate, means the actual 1985 emissions rate for the unit as specified in the National Allowance Data Base (NADB), as revised by the Administrator.

Administrative permit amendment means a revision of an Acid Rain permit pursuant to § 72.303.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

Affected source means a source that includes one or more affected units.

Affected unit means a unit, or a source that opts-in under 40 CFR part 74, that is subject to any emission reduction requirement or limitation under the Acid Rain program.

Allowable 1985 emissions rate means the allowable 1985 emissions rate for the unit as specified in the National Allowance Data Base (NADB), as revised by the Administrator.

Allowance means an authorization, allocated by the Administrator under the Acid Rain program, to emit during or after a specified calendar year up to one ton of sulfur dioxide.

Allowance held or *hold allowances* means the number of allowances recorded, or properly submitted for recordation, in an Acid Rain Allowance Tracking System account.

Allowance reserve means any bank or grouping of allowances (other than a unit or other individual account), established by the Administrator pursuant to title IV of the Act, including sections 404(a)(2), 404(g), and 416(b) of the Act and 40 CFR part 73, subpart B.

Allowance Tracking System means the system by which the Administrator issues, records, and tracks allowances.

Allowance transfer deadline means midnight of January 30 or, if January 30 is not a business day, midnight of the first business day thereafter, which is the last day on which allowances may be submitted for recordation in an affected unit's compliance subaccount for the purposes of meeting sulfur dioxide emissions limitation requirements for the previous calendar year.

Alternate designated representative means the natural person designated in a certificate of representation submitted by a designated representative in accordance with subpart B, to act on behalf of the designated representative with regard to all matters within the authority of the designated representative under the Acid Rain program.

Alternative monitoring system means a system designed to provide direct or indirect determinations of mass per unit time emissions, pollutant concentrations, and/or flow data that are demonstrated to the Administrator as having the same precision, reliability, accessibility, and timeliness as the data provided by a continuous emission monitoring system.

Applicable requirement of the Act means all of the following as they apply to units in a source, unless the context of the regulation requires otherwise:

(1) Requirements of the applicable implementation plan approved or promulgated by the Administrator under

title I of the Act that implement the relevant requirements of the Act, including any revisions to that plan, in part 52 of this chapter.

(2) Terms and conditions of any preconstruction permits issued pursuant to title I, parts C or D of the Act.

(3) Requirements of any standard and any other requirements promulgated under section 111 of the Act.

(4) Requirements of any standard promulgated for hazardous air pollutants and any other requirements under section 112 of the Act.

(5) Requirements of the Acid Rain program under title IV of the Act and 40 CFR parts 72–78;

(6) Any monitoring, reporting, and certification requirements established pursuant to section 504(b) or section 114(a)(3) of the Act.

(7) Standards and regulations governing solid waste incineration, under section 129 of the Act.

(8) Standards and regulations for consumer and commercial products, under section 183(e) of the Act.

(9) Standards and regulations for tank vessels, under section 183(f) of the Act.

(10) Requirements of the program to control air pollution for Outer Continental Shelf sources, under section 328 of the Act.

(11) Requirements of the program to protect stratospheric ozone, under title IV of the Act.

Approved compliance plan means a compliance plan, and any revision thereto, that has been approved as part of an Acid Rain permit by the Administrator or the permitting authority in accordance with this part.

Approved State permit program means a State, local, or interstate operating permit program that the Administrator has approved as meeting the requirements of 40 CFR part 70 and this part, including subpart I.

Automatic permit amendment means a revision of an Acid Rain permit pursuant to § 72.304.

Baseline means the annual quantity of fossil fuel consumed by an affected unit, measured in millions of British Thermal Units (mmBtu), as provided in 40 CFR part 73, subpart A and in 40 CFR part 72, appendices A and B.

Basic allowance allocation means an allocation of allowances made by the Administrator to an affected unit's account in the Allowance Tracking System, other than allocations made pursuant to subpart D of this part and 40 CFR part 73, subparts E and F.

Boiler means a fossil or other fuel-fired combustion device used to produce heat and to transfer heat to water, steam, or any other medium.

Boiler type means one of the categories of boilers listed in part 76.

Calendar year means January 1 through December 31, inclusive.

Certificate of representation means the completed and signed submission, using the standard form required by § 72.20, for certifying the appointment of a designated representative for an affected source, an affected unit, or a group of identified affected units.

Coal-fired means the combustion of fuel consisting of coal or any coal-derived fuel, alone or in combination with any other fuel, independent of the percentage of coal or coal-derived fuel consumed on a Btu basis.

Commence construction means that an owner or operator has either undertaken a continuous program of construction or has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction.

Commence commercial operation means to have begun to generate electricity for sale, including test generation.

Common stack means the exhaust of two or more units through a single stack with a single flue.

Compensating unit means a unit that is not otherwise an affected unit during Phase I, which is designated as an affected unit during Phase I for the purposes of providing electrical generation to make up for reduced utilization at one or more other Phase I affected units, in accordance with § 72.43.

Complete permit application means a permit application submitted under this part for which the permitting authority has issued a determination of completeness.

Compliance certification means a submission that is required by this part or 40 CFR parts 73–78, to report an affected source or an affected unit's compliance or non-compliance with a provision of the Acid Rain program to the Administrator or permitting authority, as appropriate, and that is signed and verified by the designated representative in accordance with subparts B and K of this part and 40 CFR parts 73–78.

Compliance plan, for purposes of the Acid Rain program, means the permit document submitted in accordance with subparts C and D of this part, using the standard forms specified in appendix C of this part, certifying that the source will comply with all applicable requirements under the Acid Rain program, specifying the Acid Rain compliance option(s) by which each affected unit at the source will meet the applicable emissions limitation requirements of title IV of the Act, and stating, where applicable, a schedule and description of the method or methods of compliance.

Compliance subaccount means an affected unit's Allowance Tracking System subaccount in which are held, from the date that allowances for the current calendar year are recorded under § 73.34(a) until December 31, allowances for the current calendar year and, after December 31 until the date that deductions are made under § 73.35(b), allowances for the preceding calendar year.

Construction means fabrication, erection, or installation of a unit or any portion of a unit.

Continuous emissions monitoring system means the equipment required by 40 CFR part 75 used to sample, analyze, measure, and provide, on a continuous basis, a permanent record of emissions and flow expressed in pounds per hour (lb/hr) for sulfur dioxide, in dry standard cubic feet per hour (dscfh) for volumetric flow, and in pounds per million Btu (lb/mmBtu) of heat input or pounds per hour (lb/hr), where appropriate, for nitrogen oxides. The following systems are component parts included in a continuous monitoring system: (1) Sulfur dioxide pollutant concentration monitor, (2) flow monitor, (3) nitrogen oxides pollutant concentration monitor, (4) diluent gas monitor (oxygen or carbon dioxide), and (5) a data acquisition and handling system. A continuous moisture monitor may also be included.

Control unit means a unit employing a qualifying Phase I technology in accordance with a Phase I Extension plan under § 72.42. A control unit may be a Phase I unit, or a Phase II unit that has been designated as an affected unit during Phase I pursuant to a substitution plan under § 72.41 or a reduced utilization plan under § 72.43.

Decisional body, as applied to permit appeals under Subpart H of this part, means any EPA employee who is or may reasonably be expected to act in a decision making role in a proceeding under subpart H, including the Administrator, the Chief Judicial Officer, and a Presiding Officer when not designated as a member of the EPA trial staff, and any staff of any such persons participating in the decisional process.

Demand-side measure means a measure to improve the efficiency of consumption of electricity by customers of an electric utility and includes the measures set forth in appendix 1(a) of 40 CFR part 73.

Designated representative means a natural person authorized by the owners

and operators of an affected source and of all affected units at the source, as evidenced by a certificate of representation submitted in accordance with 40 CFR part 72, subpart B, to represent and legally bind each owner and operator, as a matter of Federal law, in all matters pertaining to the Acid Rain program. Except in § 72.20(c), the term designated representative shall also mean any natural person designated in accordance with § 72.20(c) as an alternate designated representative to act on behalf of the person authorized in accordance with the preceding sentence. Whenever the term responsible official is used in 40 CFR part 70 or 71 or in a State operating permit program approved pursuant to title V of the Act and 40 CFR part 70, it shall be deemed to refer to the designated representative as defined here in so far as Acid Rain program actions, standards, requirements, or prohibitions are concerned.

Determination of completeness means a finding by a permitting authority in accordance § 72.72 of this part or 40 CFR 70.5(a) with regard to an Acid Rain permit application specifying that the application contains all the information needed to begin processing the application, consistent with the criteria in subpart G of this part.

Draft Acid Rain permit or *draft permit* means the version of the Acid Rain portion of a permit that a permitting authority with an approved program under 40 CFR part 70 offers for public comment.

Electric utility means any person, State agency, or Federal agency that sells electric energy.

Emissions means the quantity of an air pollutant emitted from an affected unit, as measured, recorded, and reported to the Administrator or a State by the designated representative and determined by the Administrator, in accordance with the emissions monitoring requirements of 40 CFR part 75.

Emissions limitation means:

(1) For the purposes of sulfur dioxide emissions, the tonnage equivalent of:

(i) The allowances allocated by the Administrator to a unit for use in a calendar year, in accordance with an Acid Rain permit application submitted to the permitting authority and consistent with the requirements of title IV of the Act and the Acid Rain program, or with the Acid Rain permit issued by the permitting authority;

(ii) As amended by allowance transfers to or from the compliance subaccount for that unit.

(2) For purposes of nitrogen oxides emissions, the limitation established pursuant 40 CFR part 76, in accordance with an Acid Rain permit application submitted to the permitting authority and consistent with the requirements of title IV of the Act and the Acid Rain program, or with an Acid Rain permit issued by the permitting authority.

Energy conservation measure means a supply-side or demand-side measure (including those that became operational before January 1, 1992).

EPA means the United States Environmental Protection Agency or, for purposes of 40 CFR part 73, any person who by delegation or contract is managing and conducting the auctions and direct sales provided in 40 CFR part 73 on behalf of EPA.

EPA Conservation Verification Protocol means a methodology developed by the Administrator to be used in calculating the electricity saved from energy conservation measures and improved unit efficiency measures for the purposes of title IV of the Act.

EPA trial staff means an employee of EPA, whether temporary or permanent, who has been designated by the Administrator under subpart H to investigate, litigate, and present evidence, arguments, and positions of EPA in any evidentiary hearing under this part. Any EPA or permitting authority employee, consultant, or contractor who is called as a witness in the evidentiary hearing by EPA trial staff shall be deemed to be EPA trial staff.

Ex parte communication means any communication, written or oral, relating to the merits of an adjudicatory proceeding under subpart H, that was not originally included or stated in the administrative record, in a pleading, or in an evidentiary hearing or oral argument under subpart H, between the decisional body and any interested person outside EPA or any EPA trial staff. Ex parte communication shall not include:

(1) Communication between EPA employees other than between an EPA trial staff and a member of the decisional body;

(2) Communication between the decisional body and interested persons outside the Agency, or any EPA trial staff, where all parties to the proceeding have received prior written notice of the proposed communication and are given an opportunity to be present and to participate therein.

Excess emissions means:

(1) Any tonnage emissions of sulfur dioxide by an affected unit during a calendar year that exceeds the sulfur dioxide allowances held as of the allowance transfer deadline in the unit's compliance subaccount; and

(2) Any tonnage emissions of nitrogen oxide by an affected unit during a calendar year that exceed the annual tonnage equivalent of the emissions limitation applicable to the affected unit as specified in 40 CFR part 76 and the affected unit's permit.

Existing affected unit, for purposes of part 73, means a unit that is both an affected unit and an existing unit, as defined in this part.

Existing unit means a unit (including a unit subject to section 111 of the Act) that commenced commercial operation before November 15, 1990. Any unit that commenced commercial operation before November 15, 1990 and that is modified, reconstructed, or repowered after November 15, 1990 shall continue to be an existing unit. Existing unit does not include simple combustion turbines, or units that serve only generators with a nameplate capacity of 25MWe or less.

Fast-track modification means a revision of an Acid Rain permit pursuant to § 72.302.

Forced outage means the removal of a unit from service or partial reduction in the heat input or electrical output of a unit due to an unplanned component failure or other unplanned condition that requires such removal or reduction immediately or within 7 days.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Generator means a device that produces electricity and is required to be reported as a generating unit pursuant to the United States Department of Energy Form 860.

Hearing clerk means an EPA employee designated by the Administrator to establish a repository for all books, records, documents, and other materials relating to such proceedings.

Heat input means the heat (in Btu's) derived from the combustion of fossil fuel in a unit and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Independent auditor means a professional engineer (1) registered in the State where the unit is located and (2) with at least 5 years of full-time experience with boilers.

Interested person means any person who submitted written comments or testified at a public hearing on a proposed permitting decision, or any person who submitted his or her name to the permitting authority to be placed on a list of interested persons.

Most stringent federally enforceable emissions limitation means the most

stringent emissions limitation for a given pollutant approved by the EPA under the Act, whether in a State implementation plan approved pursuant to title I of the Act, a new source performance standard, or otherwise. The annualization procedures at 40 CFR part 73, subpart D shall be used to calculate which of several limitations with different averaging periods is most stringent.

Multi-header unit means a unit serving more than one generator, or a generator served by more than one unit.

Nameplate capacity means the maximum electrical generating capacity that a generator can sustain over a specified period of time when not restricted by seasonal or other deratings, as measured in accordance with the United States Department of Energy standards.

National Allowance Data Base (NADB) means the data base established by the Administrator under section 402(4)(c) of the Act.

NERC region means the North American Electric Reliability Council (NERC) region, or, if one exists, subregion within which an affected unit or source is located.

New unit means a unit that commences commercial operation on or after November 15, 1990, including any such unit that serves a generator with a nameplate capacity of 25MWe or less or a simple combustion turbine.

Non-utility unit means a unit other than a utility unit.

Offset plan means a plan submitted and approved pursuant to 40 CFR part 77 for offsetting excess emissions that have occurred at an affected unit in any calendar year.

Oil-fired means the combustion of fuel oil for more than 10-percent of the annual heat input and of natural gas for the remaining annual heat input.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Opt-in unit shall have the meaning specified in 40 CFR part 74.

Owner means any of the following persons:

(1) Any holder of any portion of the legal or equitable title in an affected unit; or

(2) Any holder of a leasehold interest in an affected unit; or

(3) Any purchaser of power from an affected unit under a life-of-the-unit, firm power contractual arrangement as that term is used in section 408(i) of the Act. However, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the affected unit.

Owner or *operator* means any person who is an owner or who operates, controls, or supervises in any way an affected unit or affected source of which an affected unit is a part, and shall include but not be limited to any holding company, operating company, utility system, designated representative, or plant manager of an affected unit or affected source.

Permit modification means a revision of an Acid Rain permit pursuant to § 72.301.

Permit revision means a permit modification, automatic permit amendment, administrative permit amendment, or fast track modification.

Permitting authority means either of the following:

(1) The Administrator in the case of EPA implementation of the Acid Rain permit program; or

(2) The State air pollution control agency, local agency, other State agency, Indian tribe, or other agency authorized by the Administrator to issue proposed Acid Rain permits under title IV and V of the Act and 40 CFR part 70 and part 72, subpart I.

Permitting decision means any action taken by the Administrator under this part following, where provided for in this part, an opportunity for public comment. Permitting decision includes only permitting actions which, in the absence of an administrative appeal file pursuant to subpart H of this part within 60 days of the action, would become final agency action within the meaning of section 307 of the Act. Permitting decision does not include any interim decision, including proposed permits, draft permits, and determinations of completeness. Permitting decision also does not include any action by the Administrator pursuant to 40 CFR parts 73–76.

Person means an individual corporation, partnership, association, State, municipality, political subdivision of a State, and any agency, department, or instrumentality of the United States and any officer, agent, or employee thereof.

Phase I means the Acid Rain program compliance period beginning January 1, 1995 and ending December 31, 1999.

Phase I extension unit means an affected unit listed in 40 CFR part 72, appendix A that is either a control unit or a transfer unit pursuant to an approved compliance plan submitted under § 72.42 of this part.

Phase II means the Acid Rain program compliance period beginning January 1, 2000, and continuing into the future thereafter.

Power sales agreement is a legally-binding document between a firm associated with a new independent power production facility (IPPF) or a new IPPF and a regulated electric utility that establishes the terms and conditions for the sale of power from a specific new IPPF to the utility.

Presiding Officer means an Administrative Law Judge appointed under 5 U.S.C. 3105 and designated to preside at a hearing in a permit appeal proceeding under Subpart H.

Proposed compliance plan means a compliance plan, and any revision thereto, that has been submitted by the designated representative of an affected source on EPA Acid Rain permit application forms (as provided in appendix C of this part), which forms may be amended, revised, or modified from time to time.

Proposed Acid Rain permit or *proposed permit* means (1) in the case of State permitting, the version of an Acid Rain permit that a permitting authority with an approved operating permit program under 40 CFR part 70 submits to the Administrator after the public comment period, but prior to completion of the EPA permit review period, as provided for at 40 CFR part 70; or (2) in the case of Federal permitting, the version of a permit that the Administrator offers for public comment.

Qualifying Phase I technology means a technological system of continuous emission reduction that is demonstrated to achieve a ninety (90) percent reduction in emissions of sulfur dioxide from the emissions that would have resulted from the use of fossil fuels that were not subject to treatment prior to combustion, as provided in § 72.42.

Qualifying repowering technology means:

(1) Replacement of an existing coal-fired boiler with one of the following clean coal technologies: atmospheric or pressurized fluidized bed combustion, integrated gasification combined cycle, magnetohydrodynamics, direct and indirect coal-fired turbines, integrated gasification fuel cells, or as determined by the Administrator, in consultation with the Secretary of Energy, a derivative of one or more of the technologies, and any other technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of the

date of enactment of the Clean Air Act Amendments of 1990; or

(2) Any oil and/or gas-fired unit which has been awarded clean coal technology demonstration funding as of January 1, 1991, by the Department of Energy.

Ranking application means an application submitted to the Administrator pursuant to § 72.42 of this part.

Recordation means the official deposit or withdrawal of allowances, by the Administrator, in or from an account or subaccount in the allowance tracking system.

Reduced utilization means a reduction, during any calendar year during Phase I, in the annual average heat input at an affected unit, below the unit's baseline where such reduction subjects the unit to the requirements of § 72.43

Reduced utilization through energy conservation means reduced utilization at an affected unit demonstrated to have resulted from an energy conservation measure approved by the Administrator in accordance with § 72.43.

Reduced utilization through improved unit efficiency means reduced utilization at an affected unit demonstrated to have resulted from measures involving the modification or installation of technology, or the improvement of operating procedures at an affected unit, that increases the amount of electric generation per Btu of heat input and is approved by the Administrator in accordance with § 72.43.

Renewable energy generation means electrical energy derived from biomass, solar, geothermal, wind generation, or other resource as determined by the Administrator in consultation with the Secretary of Energy in accordance with 40 CFR part 73, subpart F and appendix 1(c) of that subpart and includes such generation by installations that became operational before January 1, 1992.

Renewal means the process by which a permit is reissued at the end of its term.

Repowering extension period means the period beginning January 1, 2000, until the affected unit for which the extension has been granted, is removed from operation to install the repowering technology or to be permanently replaced, but not later than December 31, 1993.

Schedule of compliance means an enforceable sequence of actions, measures, or operations designed to achieve or maintain compliance, or correct non-compliance, with an applicable requirement of the Act, including any applicable Acid Rain permit requirement.

Secretary of Energy means the Secretary of the United States Department of Energy or the Secretary's duly authorized representative.

Simple combustion turbine means a unit that is a rotary engine driven by a gas under pressure that is created by the combustion of any fuel. This term includes combined cycle units without auxiliary firing but excludes such units with auxiliary firing.

Source means any institutional, commercial, or industrial structure, installation, plant, or building that emits or has the potential to emit any air pollutant regulated under title IV of the Act. For purposes of section 502(c) of the Act, a source, including a source with multiple units, shall be considered a single facility.

State means one of the 48 contiguous States and the District of Columbia, and includes all non-Federal authorities, including local agencies, interstate associations, tribal authorities, and state-wide agencies with approved permit programs under 40 CFR part 70. The term State also encompasses those Native American governing bodies that the Administrator has determined, pursuant to section 301(d) of the Act, to treat as States.

State regulatory authority means a state-based authority or commission responsible for oversight of aspects of the operations of electric utilities, including but not limited to their rates and charges to customers.

Substitution unit means an affected unit that is listed in appendix B of this part and is designated as a Phase I affected unit in a substitution plan under § 72.41.

Sulfur dioxide emissions limitation requirements means the limitation on sulfur dioxide emissions specified for an affected unit in sections 403, 404, or 405 of the Act or in the unit's permit.

Sulfur-free generation means renewable energy generation or any other electrical energy generated by a process that does not have emissions of sulfur dioxide.

Sulfur-free generator means a facility that produces sulfur-free generation.

Supply-side measure means a measure to improve the efficiency of activities or facilities used by a utility to provide electricity to its customers and includes the measures set forth in appendix 1(b) of 40 CFR part 73.

Ton or *Tonnage* means any ton or fraction of a ton of emissions. For the purpose of determining compliance with the allowance requirements of the Acid Rain program, any fraction of a ton shall be deemed to equal one ton and require one allowance.

Transfer unit means a Phase I affected unit which transfers all or part of its Phase I emission reduction obligations to a control unit designated pursuant to a Phase I Extension plan under § 72.42.

Under-utilization means any reduction in heat input below a unit's baseline.

Unit means a fossil-fuel fired combustion device.

Unit account means an allowance tracking system account that is established for an affected unit.

Utility means any person, including any State or Federal agency, that produces electricity for sale.

Utility competitive bid solicitation is a public request from a regulated electric utility to select from among offers to the utility for meeting future capacity needs. A new independent power production facility (IPPF) may be regarded as having been selected in such solicitation if the utility has named the IPPF as one of the projects with which it intends to negotiate a power sales agreement.

Utility power distribution system means the portion of an electric system owned or operated by a utility that is dedicated to delivering electric energy to end-users.

Utility system or *system* means a unit or units controlled by the same utility operating company as reported on the Acid Rain data system.

Utility unit means a unit owned or operated by a utility:

(1) That serves a generator that produces electricity for sale, or

(2) That during 1985, served a generator that produced electricity for sale.

(3) Notwithstanding paragraphs (1) and (2) of this definition, a unit that was in commercial operation during 1985, but did not, during 1985, serve a generator that produced electricity for sale, shall not be a utility unit for purposes of the Acid Rain program.

(4) Notwithstanding paragraphs (1) and (2) of this definition, a unit that cogenerates steam and electricity is not a utility unit for purposes of the Acid Rain program, unless the unit is constructed for the purpose of supplying, or commences construction after November 15, 1990 and supplies, more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale.

Utilization means the heat input for a unit.

§ 72.3 Measurements, abbreviations, and acronyms.

The abbreviations, symbols, and measurements used in this part are defined as follows:

Btu—British thermal unit
mmBtu—million Btu
hr—hour
Kwh—kilowatt hour
lbs—pounds
MWe—megawatt electrical
dscfh—dry standard cubic feet per hour
NERC—North American Electric Reliability Council
DOE—Department of Energy
EPA—Environmental Protection Agency
EIA—Energy Information Administration

§ 72.4 Addresses for submissions.

(a) All submissions required by this part that must be submitted to EPA Headquarters, shall be addressed to the Chief, Permits and Technologies Section, Acid Rain Division (ANR-445), Office of Atmospheric and Indoor Air Programs, U.S. Environmental Protection Agency, 401 M Street, SW., Washington, DC 20460.

(b) All submissions required by this part that must be submitted to an EPA regional office, shall be addressed to the appropriate EPA region as follows:

Region I (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont)—Director, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, John F. Kennedy Federal Building, Boston, Massachusetts 02203.

Region II (New Jersey, New York, Puerto Rico, Virgin Islands) — Director, Air and Waste Management Division, U.S. Environmental Protection Agency, Federal Office Building, 26 Federal Plaza (Foley Square), New York, New York 10278.

Region III (Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia)—Director, Air, Radiation and Toxics Management Division, U.S. Environmental Protection Agency, 841 Chestnut Building, Philadelphia, Pennsylvania 19107.

Region IV (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee)—Director, Air, Pesticides, and Toxics Management Division, U.S. Environmental Protection Agency, 345 Courtland Street, NE., Atlanta, Georgia 30365.

Region V (Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin)—Director, Air and Radiation Division, U.S. Environmental Protection Agency, 230 South Dearborn Street, Chicago, Illinois 60604.

Region VI (Arkansas, Louisiana, New Mexico, Oklahoma, Texas)— Director, Air, Pesticides, and Toxics Division, U.S. Environmental Protection Agency, 1445 Ross Avenue, Dallas, Texas 75202.

Region VII (Iowa, Kansas, Missouri, Nebraska)—Director, Air and Toxics Division, U.S. Environmental Protection Agency, 726 Minnesota Avenue, Kansas City, Missouri 66101.

Region VIII (Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming)—Director, Air and Toxics Division, U.S. Environmental Protection Agency, 1860 Lincoln Street, Denver, Colorado 80295.

Region IX (Arizona, California, Guam, Hawaii, Nevada) — Director, Air and Toxics Division, U.S. Environmental Protection Agency, 75 Hawthorne Street, San Francisco, California 94105.

Region X (Alaska, Idaho, Oregon, Washington)—Director, Air and Toxics Division, U.S. Environmental Protection Agency, 1200 Sixth Avenue, Seattle, Washington 98101.

(c) All submissions required by this part that must be sent to a State permitting authority with an approved permit program under this part and 40 CFR part 70, shall be addressed to the applicable permitting authority as provided in 40 CFR part 70, and to the following State air pollution agencies:

State of Alabama, Air Pollution Control Division, 645 S. McDonough Street, Montgomery, Alabama 36104.

State of Arizona, Department of Health Services, 1740 West Adams Street, Phoenix, Arizona 85007.

State of Arkansas, Division of Air Pollution Control, Department of Pollution Control and Ecology, 8001 National Drive, P.O. Box 9583, Little Rock, Arkansas 72209.

State of California, Air Resources Board, 1102 Q Street, Sacramento, California 95814.

State of Colorado, Department of Health, Air Pollution Control Division, 4210 East 11th Avenue, Denver, Colorado 80220.

State of Connecticut, Department of Environmental Protection, State Office Building, Hartford, Connecticut 06115.

State of Delaware, Delaware Department of Natural Resources and Environmental Control, 89 Kings Highway, P.O. Box 1401, Dover, Delaware 19901.

District of Columbia, Department of Consumer and Regulatory Affairs, 614 H Street, NW., Washington DC 20001.

State of Florida, Bureau of Air Quality Management, Department of Environmental Regulation, Twin Towers Office Building, 2600 Blair Stone Road, Tallahassee, Florida 32301.

State of Georgia, Environmental Protection Division, Department of Natural Resources, 205 Butler Street, SE., East Tower, Atlanta, Georgia 30334.

State of Idaho, Department of Health and Welfare, Statehouse, Boise, Idaho 83701.

State of Illinois, Division of Air Pollution Control, 2200 Churchill Road, Springfield, Illinois 62706.

State of Indiana, Indiana Department of Environmental Management, 105 South Meridian Street, P.O. Box 6015, Indianapolis, Indiana 46206.

State of Iowa, Iowa Department of Water, Air, and Waste Management, Henry A. Wallace Building, 900 East Grand, Des Moines, Iowa 50319.

State of Kansas, Kansas Department of Health and Environment, Bureau of Air Quality and Radiation Control, Forbes Field, Topeka, Kansas 66620.

State of Kentucky, Division of Air Pollution Control, Department for Natural Resources and Environmental Protection, U.S. 127, Frankfort, Kentucky 40601.

State of Louisiana, Program Administrator, Air Quality Division, Louisiana Department of Environmental Quality, P.O. Box 44096, Baton Rouge, Louisiana 70804.

State of Maine, Department of Environmental Protection, State House, Augusta, Maine 04330.

State of Maryland, Air Management Administration, Maryland Department of the Environment, 2500 Broening Highway, Baltimore, Maryland 21224.

Commonwealth of Massachusetts, Massachusetts Department of Environmental Quality Engineering, Division of Air Quality Control, One Winter Street, Boston, Massachusetts 02108.

State of Michigan, Air Pollution Control Division, Michigan Department of Natural Resources, Stevens T. Mason Building, 8th floor, Lansing, Michigan 48926.

State of Minnesota, Minnesota Pollution Control Agency, Division of Air Quality, 520 Lafayette Road, St. Paul, Minnesota 55155.

State of Mississippi, Bureau of Pollution Control, Department of Natural Resources, P.O. Box 10385, Jackson, Mississippi 39209.

State of Missouri, Department of Natural Resources, P. O. Box 1368, Jefferson City, Missouri 65101.

State of Montana, Department of Health and Environmental Services, Cogswell Building, Helena, Montana 59601.
State of Nebraska, Department of Environmental Control, P.O. Box 94877, State House Station, Lincoln, Nebraska 68502.
State of Nevada, Department of Conservation and Natural Resources, Division of Environmental Protection, 201 South Fall Street, Carson City, Nevada 89710.
State of New Hampshire, New Hampshire Air Resources Agency, Health and Welfare Building, Hazen Drive, Concord, New Hampshire 03301.
State of New Jersey, Department of Environmental Protection, Division of Environmental Quality, Enforcement Element, John Fitch Plaza, CN-027, Trenton, New Jersey 08625.
State of New Mexico, Director, New Mexico Environmental Improvement Division, Health and Environmental Department, 1190 St. Francis Drive, Santa Fe, New Mexico 87503.
State of New York, Department of Environmental Conservation, Division of Air Resources, 50 Wolf Road, New York, New York 12233.
State of North Carolina, Environmental Management Commission, Department of Natural and Economic Resources, Division of Environmental Management, Attention: Air Quality Section, P.O. Box 27687, Raleigh, North Carolina 27611.
State of North Dakota, State Department of Health and Consolidated Laboratories, Division of Environmental Engineering, State Capitol, Bismark, North Dakota 58501.
State of Ohio, Ohio Environmental Protection Agency, 1800 Watermark Drive, Box 1049, Columbus Ohio 43266-0149.
State of Oklahoma, Oklahoma State Department of Health, Air Quality Service, P.O. Box 53551, Oklahoma City, Oklahoma 73152.
State of Oregon, Department of Environmental Quality, Yeon Building, 522 S.W. Fifth, Portland, Oregon 97204.
Commonwealth of Pennsylvania, Department of Environmental Resources, 105 S. Second Street, P.O. Box 2357, Harrisburg, Pennsylvania 17120.
State of Rhode Island, Department of Environmental Management, 204 Cannon Building, Davis Street, Providence, Rhode Island 02908.
State of South Carolina, Office of Environmental Quality Control, Department of Health and Environmental Control, 2600 Bull Street, Columbia, South Carolina 29201.
State of Tennessee, Department of Public Health, Division of Air Pollution Control, 256 Capitol Hill Building, Nashville, Tennessee 37219.
State of Texas, Air Pollution Control Board, 6330 Highway 290 East, Austin, Texas 78723.
State of Utah, Department of Health, Bureau of Air Quality, 288 North 1460 West, P.O. Box 16690, Salt Lake City, Utah 84116-0690.
State of Vermont, Vermont Agency of Environmental Conservation, Air Pollution Control, State Office Building, Montpelier, Vermont 05602.
Commonwealth of Virginia, Virginia Department of Air Pollution Control, P.O. Box 10089, Ninth Street Office Building, Richmond, Virginia 23219.
State of Washington, Department of Ecology, Olympia, Washington 98504.
State of West Virginia, Air Pollution Control Commission, 1558 Washington Street East, Charleston, West Virginia 25311.
State of Wisconsin, Department of Natural Resources, P.O. Box 7921, Madison, Wisconsin 53707.

As appropriate, the State air pollution control agency shall forward any permit application to the approved permitting authority if other than the State air pollution control agency for processing.

(d) For all submissions required by this part to be submitted to a State, an EPA Regional office, or EPA Headquarters, copies shall also be sent to the State permitting authority or air pollution control agency, to the appropriate EPA Regional office, and to EPA Headquarters. In addition, pursuant to Section 408(g) of the Act, informational copies of all submissions shall be sent to the State electric utility rate regulatory authority in the case of regulated utility units.

§ 72.5 Federal authority.

Under authority of sections 114 and 301 of the Act, the Administrator reserves the right to:

(a) Secure information needed for the purpose of developing or implementing any standard, requirement, or prohibition under the Act or under 40 CFR parts 70-78, or of determining whether any person is in violation of any standard, requirement, or prohibition of the Act, this part, or 40 CFR parts 73-78;

(b) Make inspections, conduct tests, examine records, and require the designated representative, the owner, or the operator of an affected unit to submit information reasonably required for the purpose of developing or implementing any standard, requirement, or prohibition under this part and 40 CFR parts 73-78; and

(c) Call witnesses and compel the production of documents.

§ 72.6 State authority.

Consistent with section 116 of the Act, the provisions of this part shall not be construed in any manner to preclude any State or political subdivision thereof from adopting and enforcing any other air quality requirement applicable to an affected source or unit; *provided* that such requirement is not less stringent than, and does not alter any requirement applicable to such unit or source prescribed under this part; and *Provided, further,* That such requirement if articulated in an operating permit, is expressed in a portion of the permit separate from the portion containing the Acid Rain program requirements. Nothing in this section shall authorize a State permitting authority to modify or alter any Acid Rain program requirement except as provided in title IV and elsewhere in this part.

§ 72.7 Applicability.

(a) Each stationary source with one or more of the following kinds of units shall be deemed an affected source subject to the permitting requirements of this part:

(1) Each source that includes an affected unit listed in appendix A of this part;

(2) During Phase I each source that includes a unit not listed in appendix A of this part that is designated as an affected unit as follows:

(i) A substitution unit designated in a substitution plan pursuant to § 72.41; or

(ii) A compensating unit designated in a reduced utilization plan pursuant to § 72.43;

(3) During Phase II each source that includes an existing unit listed in appendix B or any other existing unit;

(4) During Phase II each source that includes a new unit;

(5) Each source that includes a unit that cogenerates steam and electricity that is constructed for the purpose of serving a generator that supplies, or commences construction after November 15, 1990 and serves a generator that supplies, more than one-third of its potential electric output capacity and more than 25MWe electric output to any utility power distribution system for sale;

(6) Each source that includes a unit that before enactment did not serve a generator with a nameplate capacity of greater than 25MWe and on or after enactment was modified to serve a generator of greater than 25MWe; and

(7) Except as provided in 40 CFR part 74, each source that elects to become an affected source pursuant to 40 CFR part 74.

(b) Except as otherwise provided, the following types of units are not subject to Acid Rain permitting under this part, unless they elect to become an affected unit pursuant to 40 CFR part 74:

(1) An existing simple combustion turbine;

(2) Any existing unit that did not and does not currently serve a generator with a nameplate capacity of greater than 25MWe;

(3) Any boiler that does not serve a generator;

(4) A unit that cogenerates steam and electricity, unless the unit is constructed for the purpose of serving a generator that supplies, or commences construction after November 15, 1990 and serves a generator that supplies, more than one-third of its potential electric output capacity and more than 25MWe electric output to any utility power distribution system for sale;

(5) A certified qualifying small power production source or certified qualifying cogeneration source (as defined in Section 405(g)(6)(A) of the Act and as determined in accordance with 40 CFR part 73) that meets the criteria of paragraph (6)(i), below; or

(6) A new independent power production source if:

(i) As of November 15, 1990:

(A) A power sales agreement has been executed that is applicable to the source; or

(B) The source is the subject of a State regulatory authority order requiring an electric utility to:

(1) Enter into a power sales agreement with purchase capacity from the source, or

(2) (For purposes of establishing terms and conditions of the electric utility's purchase of power) enter into arbitration concerning the source; or

(C) An electric utility has issued a letter of intent or similar instrument committing to purchase power from the source at a previously offered or lower price and a power sales agreement is executed within a reasonable period of time; or

(D) The source has been selected as a winning bidder in a utility competitive bid solicitation; and

(ii) It is used for the generation of electricity, eighty percent or more of which is sold at wholesale; and

(iii) It is nonrecourse project financed (as such term is defined by the Secretary of Energy) within 3 months of the date of enactment of the Act (November 15, 1990); and

(iv) It is a new unit that would otherwise be required to hold allowances under the Acid Rain program.

(c) Except as otherwise provided, non-utility units are not subject to Acid Rain permitting under this part, unless they elect to become an affected unit pursuant to 40 CFR part 74.

(d) As provided in 40 CFR 70.3(b), affected sources and affected units may not be exempted from the permitting requirements of the Acid Rain program.

(e)(1) Whenever any requirement or prohibition in this part or in 40 CFR parts 73–78 applies to an affected source, or to the owner(s), operator(s), or the designated representative of an affected source, the requirement or prohibition shall apply to and be fully enforceable against each owner and operator of the affected source and of each affected unit at the source (including any new owner notwithstanding any change of ownership), each of whom shall (notwithstanding any private indemnification agreements between and among the designated representatives, the owners, and the operators) be liable, as a matter of Federal law, to comply with any such requirement or prohibition, and for any violation of any such requirement or prohibition.

(2) Whenever any requirement or prohibition in this part or in 40 CFR parts 73–78 applies to an affected unit or to the owner(s), operator(s), or designated representative of an affected unit, the requirement or prohibition shall apply to and be fully enforceable against each owner and operator of the affected unit (including any new owner notwithstanding any change of ownership), each of whom shall (notwithstanding any private indemnification agreements between and among the designated representatives, the owners, and the operators) be liable, as a matter of Federal law, to comply with any such requirement or prohibition, and for any violation of any such requirement or prohibition.

(3) Nothing in paragraphs (e) (1) or (2) of this section shall affect or limit private commercial agreements between owners, operators, and designated representatives, or with any third party insurer with regard to private indemnification rights and obligations; *provided* that no such private agreement shall give rise to any defense as a matter of Federal law to the applicability, enforceability, or liability of any such person with regard to any Acid Rain program requirement.

§ 72.8 Prohibitions.

(a) No permit shall be issued to an affected source under this part or 40 CFR parts 70 and 71 until a designated representative for the source and each affected unit at the source has been certified, pursuant to subpart B of this part.

(b) No designated representative, owner or operator of any source subject to this part shall operate an affected unit except in accordance with the requirements of this part and 40 CFR parts 73–78.

(c) It shall be a violation of the Act for a designated representative, an owner, or an operator of an affected unit to use any Acid Rain compliance option except in accordance with this part.

(d) It shall be a violation of the Act for a designated representative, an owner, or an operator of an affected unit to delegate any responsibility to take any action, or comply with any standard, requirement, or prohibition of this part or 40 CFR parts 73–78 except as authorized in subpart B.

(e) A violation by the designated representative, by an owner, or by an operator of an affected unit subject to the provisions of this part, of any standard, requirement, or prohibition of this part shall be a violation of the Act.

§ 72.9 Signatory requirements.

(a) All Acid Rain program submissions required to be made on behalf of affected sources and affected units pursuant to this part, 40 CFR parts 70, 71, and 40 CFR parts 73 through 78, including the submissions specified in § 72.21, shall be made in writing or by an authorized electronic transmission by the designated representative for the source's owners and operators and, when submitted in writing, shall be submitted by certified mail. Certified mail shall include U.S. Postal Service certified mail, or mail delivery certified by any other independent third-party postal carrier. In each submission, the designated representative shall sign and certify:

(1) That the procedure specified in the representation agreement, pursuant to § 72.20, for obtaining the authorization of the owners and operators of the affected source or unit, as applicable, to take such action has been complied with; and

(2) The following statement: I certify under penalty of law that I have personally examined, and am familiar with, the information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the

information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including the possibility of fine or imprisonment.

(b) The permitting authority shall only act upon submissions that have been signed, certified, and filed by the duly authorized designated representative for the affected units at the source.

§ 72.10 Recordkeeping.

All notices, records, and reports (including compliance certifications), required to be maintained, issued to any person, or submitted to the Administrator, a State air pollution control agency, or a permitting authority pursuant to this part, shall be kept on file at the source for a period of 5 years. This period may be extended for cause at any time prior to the end of 5 years in writing by the Administrator or the permitting authority.

§ 72.11 Availability of information.

The availability to the public of information provided to, or otherwise obtained by, the Administrator under this part shall be governed by 40 CFR part 2.

§ 72.12 Computation of time.

(a) Any time period scheduled to begin on the occurrence of a date, number of days, act, or event shall begin on the day the act or event occurs.

(b) Any time period scheduled to begin before the occurrence of a date, number of days, act, or event shall be computed so that the period ends on the day before the act or event occurs.

(c) If the final day of any time period falls on a weekend or a Federal holiday, the time period shall be extended to the next business day.

(d) Whenever a party or interested person has the right, or is required, to act within a prescribed time period after service of notice or other document upon him or her by mail, 3 days shall be added to the prescribed time.

§ 72.13 False certifications.

Anyone making a material false certification under this part shall be subject to enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.

Subpart B—Designated Representative—Certification Procedure

§ 72.20 Certificate of representation.

(a) No permit shall be issued under this part to an affected source, nor shall any allowance acquisition or transaction be recorded for an affected unit's Allowance Tracking System account established under 40 CFR part 73, until a designated representative of the affected source and of each affected unit at the source has filed a complete certificate of representation with the Administrator in accordance with this section, with regard to all matters under title IV of the Act and under this part and 40 CFR parts 73–78.

(b) The certificate of representation shall include:

(1) A statement that the representative was selected by an agreement binding on each and every owner and operator of the affected source and of each affected unit at the source;

(2) A statement that daily notice by publication in a journal of national and general circulation has been given of such agreement for a period of two weeks;

(3) A statement that actual written notice of such agreement has been given to each owner and operator of an affected unit at the source;

(4) A list of the owners and operators of the source and of each affected unit at the source;

(5) A statement that the designated representative has all necessary authority to carry out the duties and responsibilities of the designated representative on behalf of each owner or operator of an affected unit at the source under the Acid Rain program, 40 CFR parts 72–78 and that the owners and operators of the affected source, and of each affected unit at the source, shall be fully bound and liable for any actions taken or submissions made by the designated representative;

(6) *Multiple Owners.* (i) Where there are multiple owners in an affected unit the certificate of representation shall certify:

(A) That allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in proportion to each owner's legal, equitable, leasehold, or contractual reservation or entitlement in accordance with section 408(i) of the Act; or

(B) If such multiple owners have expressly provided for a different distribution by an agreement binding on each and every owner of the unit, that allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the agreement;

(ii) Except as otherwise provided in this subsection, where all legal or equitable title to or interest in an affected unit is held by a single person, the certificate of representation shall certify that all allowances in the unit's Allowance Tracking System account are deemed to be held for that person.

(iii) Notwithstanding paragraphs (b)(6)(i) and (ii) of this section or any private agreements between multiple owners, each owner of an affected unit with multiple owners shall, as a matter of Federal law, be liable for the unit's compliance with the requirements and prohibitions of the Acid Rain program and for any violation of any such requirement or prohibition.

(7) A statement that the designated representative will abide by the fiduciary responsibilities imposed pursuant to this subpart and the agreement specified in paragraph (b)(1) of this section.

(8) A statement that the owners and operators of an affected source, or an affected unit at a source, shall be bound by any order issued to the designated representative by the Administrator or a court regarding the unit or source.

(c) *Alternate designated representative.* (1) The certificate of representation may designate an alternate designated representative to act on behalf of the designated representative, owners, and operators of the source and each affected unit at the source, in the event the certifying designated representative is absent or otherwise not available to perform actions and duties specified in this part. The alternate designated representative shall be a natural person and shall be authorized if the following conditions are met:

(i) The certificate of representation submitted by the designated representative under this section identifies the full name, address, telephone number, and facsimile number (if any) of the alternate designated representative; certifies that the alternate was selected in accordance with the agreements, conditions, and procedures specified in paragraph (b) of this section; and certifies that the agreement of representation specified in paragraph (b) of this section includes a procedure for the owners, operators, and designated representative of the source and the affected units to authorize the alternate to act in lieu of the designated representative;

(ii) The alternate designated representative signs the certificate of representation, indicating that he or she is aware of his or her duties and responsibilities as alternate designated representative; and

(iii) The designated representative certifies in the certificate of representation that the designated representative, the owners, and the operators of the affected source, and of

each affected unit at the source, shall be fully bound and liable for any actions taken or submissions made by the alternate designated representative;

(2) Only one alternate designated representative shall be authorized to act on behalf of the designated representative.

(3) In the event of a conflict, any action taken or submission made by the designated representative shall take precedence over any action taken by the alternate designated representative if, in the Administrator's judgement, the actions are concurrent and conflicting.

(4) The designated representative and the owners and operators of the affected source, or of an affected unit at the source, shall each be liable for any actions taken by the alternate designated representative with regard to the source or the unit. Any action, representation or failure to act by the alternate designated representative shall be deemed to be an action of the designated representative, with all the rights, duties and responsibilities pertaining thereto.

(5) The alternate designated representative may be changed at any time by the designated representative upon submission of a new certificate of representation to the Administrator as provided in § 72.22. Any such change shall be deemed an administrative amendment of the permit.

(6) The alternate designated representative shall be subject to the provisions of this part and 40 CFR parts 73 through 78, that apply to the designated representative, when acting in that capacity.

(7) Except as provided in this section, whenever the term designated representative is used in this part (other than paragraph (c) of this section), in 40 CFR parts 73–78, or in the Acid Rain program generally, it shall be construed to include the alternate designated representative.

(d) A copy of the certificate of representation submitted by the designated representative of an affected unit pursuant to this section shall be:

(1) Included in and attached to each permit application, proposed compliance plan, and permit issued under this part; and

(2) Deemed to be incorporated into each submission made by the designated representative pursuant to the Acid Rain program, by operation of law.

(e) Unless otherwise required by the Administrator, the documents of agreement and notice referred to in the certificate of representation shall not be submitted to the Administrator or to the permitting authority. Neither the Administrator nor the permitting authority shall be under any obligation to review or evaluate the sufficiency of any such documents, if submitted.

§ 72.21 Duties of the designated representative.

(a) The designated representative shall represent and legally bind as a matter of Federal law each owner and operator of the affected source represented, and of each affected unit at the source, in all matters pertaining to the Acid Rain program, including but not limited to: the holding, transfer, or disposition of allowances allocated to the unit in accordance with 40 CFR part 73; the submission of or compliance with permits, permit applications, permit revisions, permit renewals, compliance plans, and compliance certifications under this part; and the submission of or compliance with excess emissions penalties and offset plans in accordance with 40 CFR part 77. Notwithstanding the preceding sentence and provisions elsewhere in this part, and consistent with § 72.7(e):

(1) Whenever a requirement or prohibition of the Acid Rain program applies to an affected source it shall be deemed to apply to the designated representative and each and every owner and operator of an affected unit at the source;

(2) Whenever a requirement or prohibition of the Acid Rain program applies to an affected unit it shall be deemed to apply to the designated representative and each and every owner and operator of an affected unit only. Except as provided in this part with regard to multi-unit compliance plans, the owners and operators of a unit at a source shall not be liable for any violation by any other affected unit located at the same source of any such affected unit requirement or prohibition.

(b) The designated representative shall sign, certify, and file all submissions under the Acid Rain program, including, but not limited to:

(1) Acid Rain permit applications, permit renewal applications, proposed compliance plans, and proposed permit or compliance plan revisions in accordance with §§ 72.41 through 72.48 and Subpart C;

(2) Submissions required to be made pursuant to any Acid Rain compliance option selected for one or more units at the affected source pursuant to subpart D;

(3) Submissions concerning the holding, transfer, or disposition of allowances to or from a unit account, pursuant to 40 CFR part 73:

(4) Submissions of the compliance certifications required pursuant to subpart K, including:

(i) All emissions monitoring reports required pursuant to 40 CFR part 75; and

(ii) All Acid Rain operation and maintenance reports required by an Acid Rain compliance option under subpart D;

(5) Payments of any excess emissions penalties required pursuant to 40 CFR part 77; and

(6) Submissions of any excess emissions offset plans required pursuant to 40 CFR part 77.

(c) In each periodic (annual, quarterly, monthly, and other) compliance certification required by subpart K of this part and 40 CFR parts 73–78, the designated representative shall include:

(1) A statement in the annual certification required by § 72.402 that all allowance transactions, and all proceeds from any such transfers have been effectuated in accordance with the representation agreement required by § 72.20(c);

(2) Statements, as specified elsewhere in the applicable provisions of this part and 40 CFR parts 73–78, concerning the unit's compliance status with regard to requirements specified in the unit's Acid Rain permit and approved compliance plan; and

(3) A certification, as required by § 72.8(a) pursuant to § 72.20(c)(5), that the representative is authorized by the owners and operators to take such action.

(d) The designated representative shall provide each owner and operator with a copy of any Acid Rain program submission and of any written determination of the Administrator or the permitting authority covering the affected source.

(e) The designated representative of two or more units using a common stack shall submit a notice and an emissions monitoring plan to the Administrator in accordance with 40 CFR 75.11(a), and shall include a common-stack plan in the permit application for the source, pursuant to § 72.50.

(f) The designated representative shall certify each submission in accordance with § 72.9.

(g) Whenever any requirement or prohibition in this part or 40 CFR parts 73–78 applies to the designated representative of an affected unit or affected source, the requirement or prohibition shall apply to and be fully enforceable against each and every owner and operator of the affected unit or affected source (as applicable), each of whom shall be liable, as provided in paragraph (a) of this section and

§ 72.7(e), for any violation of such requirement or prohibition.

§ 72.22 Changing the designated representative.

(a) The designated representative of an affected source may be changed at any time by submitting a superseding certificate of representation in accordance with § 72.20. Any such submission properly made shall be deemed an administrative amendment of the permit upon its receipt.

(b) Notwithstanding any such change, all actions by the previous designated representative prior to the time when the superseding certificate of representation is received by the Administrator shall be binding on the new designated representative and on the owners and operators of the affected unit's at the source.

(c) No permitting authority shall accept any submission under the Acid Rain program other than from the designated representative for which a certificate of representation is in effect in accordance with § 72.20 and this subpart.

§ 72.23 Objections.

(a) Once a representative has been properly designated pursuant to the notice and comment procedure established by this subpart, the Administrator shall rely on the certificate of representation unless and until a superseding certificate is filed with the Administrator pursuant to § 72.22.

(b) Other than as a result of a certificate of representation submitted pursuant to § 72.22 for the purpose of changing the designated representative, no objection or other communication submitted to the Administrator or the permitting authority concerning the representation of the designated representative shall affect any recordation of an allowance transfer properly submitted pursuant to 40 CFR part 73, or the processing of any permit program submissions properly made pursuant to this part, or any other submission made by the designated representative pursuant to the Acid Rain program. With respect to any objection concerning the representation of the designated representative, in no event shall the Administrator stay any future allowance transfers or permit submissions.

(c) Neither the United States, the Administrator, the EPA, any EPA employee, nor any permitting authority will adjudicate any private legal dispute concerning the representation of any designated representative, including private disputes concerning the proceeds of allowance transfers.

(d) No objection or new certificate of representation filed by the owners or operators shall affect the finality of any permit action resulting from a submission pursuant to this part, by a designated representative duly certified pursuant to this subpart.

§ 72.24 Change owners and operators.

(a) In the event a new owner or operator of an affected unit is not included in the list of owners and operators submitted in the certificate of representation pursuant to § 72.20, such new owner or operator shall be deemed to be subject to the certificate of representation, to any permit application, permit, compliance plan, or offset plan submitted or approved under this part, and to the actions of the designated representative of the unit by operation of law.

(b) Within 30 days following the transaction giving rise to any change in ownership or operator including the addition of a new owner or operator, the designated representative shall submit a revision to the certificate of representation amending the list of owners and operators to include the change.

(c) Any new owner or operator of an affected source or of an affected unit at the source shall be subject to and be bound by, the provisions of any Acid Rain program submission made by the designated representative for the source and the Acid Rain permit and compliance plan or offset issued to the source by a permitting authority in accordance with this part.

(d) Notwithstanding the previous subsection, any change in ownership or interest in an affected unit shall require the submission of a new certificate of representation for the designated representative.

§ 72.25 Designated representative identification number.

The Administrator shall issue to each designated representative properly certified in accordance with this subpart an Acid Rain program personal identification number (DR PIN#) within 30 days of receiving a certificate of representation. Each submission made by the designated representative pursuant to this part and 40 CFR parts 73–78, shall include the DR PIN#.

Subpart C—Acid Rain Permit Applications and Compliance Plans

§ 72.30 Requirement to apply.

(a) *Duty to apply.* (1) It shall be a violation of title IV of the Act and this part for any affected source with an affected unit as specified in § 72.7, to fail to have an Acid Rain permit application or permit that covers its Acid Rain program requirements in accordance with this part and 40 CFR parts 73–78.

(2) Any designated representative of any affected source that does not have an Acid Rain permit shall submit a complete Acid Rain permit application, including an Acid Rain compliance plan for each affected unit at the source, in accordance with § 72.32 and subpart D.

(3) Where an affected source consists of more than one affected unit, the permit application or permit shall cover and be binding on all such units.

(4) The designated representative for the affected source shall submit the permit application on behalf of all the owners and operators of the affected units at the source.

(b) Deadlines. (1) Phase I. For any source with an affected unit meeting the criteria specified in § 72.7(a)(1), a complete Acid Rain permit application shall be submitted to the Administrator on or before February 15, 1993.

(2) Phase II Sulfur Dioxide. For any source with an existing affected unit as specified in § 72.7(a)(3), a complete Acid Rain permit application for sulfur dioxide shall be submitted to the permitting authority on or before January 1, 1996.

(3) Phase II Nitrogen Oxides. For any source with an existing affected unit as specified in § 72.7(a)(3), a complete Acid Rain permit application for nitrogen oxides revising the Phase II permit issued pursuant to paragraph (b)(2) of this section, shall be submitted to the permitting authority on or before January 1, 1998.

(4) New units. For any source with a new unit, as specified in § 72.7(a)(4), a complete Acid Rain permit application shall be submitted to the permitting authority in accordance with the deadlines specified in § 72.45(b).

(5) Acid Rain compliance option deadlines. The deadline for submitting applications for one or more Acid Rain compliance option as provided in subpart D, including a permit application for any source with a unit designated, as provided in § 72.7(a)(2), pursuant to any such option, shall be the deadline specified in the relevant section of subpart D.

(c) Duty to reapply. Except as provided above for initial Phase I and Phase II permitting, a complete Acid Rain permit renewal application shall be submitted for each source with an affected unit at least 18 months prior to

the expiration of the unit's existing permit.

(d) Unless provided elsewhere in this part, copies of all permit applications and proposed compliance plans provided for in this part shall be submitted to the State permitting authority or air quality agency for the State where the source is located, to the U.S. Environmental Protection Agency Regional Office for the Region where the affected source is located, and to the U.S. Environmental Protection Agency Acid Rain Division Headquarters office, as provided in § 72.4(d).

§ 72.31 Information requirements for acid rain permit applications.

All Acid Rain permit applications shall contain the following information, which shall be submitted on the appropriate Acid Rain permit application forms as provided in appendix C of this part:

(a) *Affected source information.* For the affected source for which the application is submitted, specify using SF# 7231 in appendix C of this part:

(1) The source name;

(2) The source mailing address;

(3) The source location;

(4) The affected units and other units at the source;

(5) During Phase I, the NERC region or sub-region where the source is located, and the name of the utility system for the source.

(6) During Phase I, the aggregate baseline of all Phase I units in the system of which the source is a part;

(7) That 5 year projected utilization generation, and schedule of planned outages for each unit at the source are on record at the source.

(8) Designated representative information as follows:

(i) The name, mailing address, telephone number, facsimile number, and Acid Rain identification number for the designated representative (and alternate designated representative); and

(ii) The current certificate of representation pursuant to subpart B.

(9) The standard provisions and prohibitions set forth in § 72.54.

(b) *Affected unit information.* For each affected unit at the source for which the Acid Rain permit application is submitted, specify using SF# 7231A in appendix C of this part:

(1) The name and Acid Rain unit identification number, as provided in appendix A or B of this part, or as reported on the NADB, of the unit;

(2) Whether the unit is an existing, opt-in, or new unit;

(3) Each unit's boiler type, as provided in 40 CFR part 76;

(4) Whether the unit is a multi-header unit;

(5) Whether the unit shares a common stack with one or more other units;

(6) The most stringent Federally enforceable emissions limitation for sulfur dioxide and nitrogen oxides applicable to the unit.

(7) The Acid Rain program emissions limitations for sulfur dioxide and nitrogen oxides applicable to the unit;

(8) Projected annual utilization for the unit for 1993–1999 (in mmBtu) as reported on DOE Form 767 filed in the year in which the application is submitted; and

(9) A compliance plan for the unit, as provided in § 72.32, and Subpart D (if applicable).

(c) *Monitoring system information*—(1) *Monitoring plan.* (i) Attach the monitoring plan for each affected unit at the source, approved by the Administrator pursuant to 40 CFR part 75; or

(ii) During Phase I, attach the proposed monitoring plan for each affected unit for approval by the Administrator pursuant to 40 CFR part 75; or

(iii) During Phase I, indicate that a proposed monitoring plan has been submitted to the Administrator for each affected unit for approval pursuant to 40 CFR part 75.

(2) *Monitor certification.* (i) Attach the certification for each monitor certified pursuant to 40 CFR part 75; or

(ii) During Phase I, attach initial verification test results for each monitor for certification pursuant to 40 CFR part 75; or

(iii) During Phase I, indicate that such test results have been submitted to the Administrator for certification pursuant to 40 CFR part 75; or

(iv) During Phase I, certify that such test results will be submitted to the Administrator for certification in a timely manner as provided in 40 CFR part 75.

(d) *Prohibition.* Each permit application shall include a requirement that the source will comply with all requirements of the Acid Rain program, including those set forth in this part and 40 CFR part 73–78, and all reporting and recordkeeping requirements of the Acid Rain program.

§ 72.32 Acid rain compliance plan requirements.

(a) General. (1) Each Acid Rain permit application shall include a compliance plan specifying one or more Acid Rain compliance option for each affected unit at the affected source, using the appropriate standard form(s) provided for in appendix C of this part.

(2)(i) A multi-unit compliance plan for units located at more than one affected source may be approved pursuant to this part; *Provided* that such compliance plan is signed and certified by the designated representative for each source with an affected unit governed by the plan, and is cross-referenced and incorporated as approved by the permitting authority without modification into the respective Acid Rain permit applications and permits for the affected sources. The designated representative for a source with an affected unit governed by a multi-unit compliance plan involving units located at one or more other source, shall include in the permit application for the source informational copies of the complete permit(s) or permit application(s) for the other source(s), including the compliance plans for each affected unit at the other source(s) governed by the multi-unit plan.

(ii) Notwithstanding paragraph (d)(2)(i), of this section, no substitution plan or nitrogen oxides averaging plan shall be approved unless all units subject to such plan have the same designated representative.

(iii) The owners, operators, and designated representative of an affected unit governed by a multi-unit compliance plan shall be liable for any violation of the plan's requirements or prohibitions at any affected unit governed by the multi-unit plan, including violations at a unit governed by the plan that is located at another source.

(3) In no event shall an affected unit, including a unit which is subject to more than one compliance option, shall have more than one designated representative.

(4) Nothing in this section regarding compliance plans or in title V of the Act shall be construed as affecting allowances, except as authorized by this part.

(b) Each affected unit shall employ one or more of the compliance options specified in paragraphs (b)(1)–(8) of this section, as provided further in subpart D, to meet its Acid Rain program emissions limitation requirements. The designated representative for each such affected unit shall submit a plan, using the appropriate standard forms specified in appendix C of this part, selecting any such option(s) as follows:

(1) For the standard compliance method for sulfur dioxide or nitrogen oxides, the requirements set forth in § 72.40(b);

(2) For substitution plans, the requirements set forth in § 72.41;

(3) For Phase I Extension plans, the requirements set forth in § 72.42;

(4) For reduced utilization plans, the requirements set forth in § 72.43;

(5) For repowering extension plans, the requirements set forth in § 72.44;

(6) For nitrogen oxides emissions averaging plans, the requirements set forth in § 72.46 and 40 CFR part 76;

(7) For nitrogen oxides alternative emissions limitation plans, the requirements set forth in § 72.47 and 40 CFR part 76; and

(8) For nitrogen oxides Phase I Extension plans, the requirements set forth in § 72.48 and 40 CFR part 76.

(c) The designated representative for an opt-in unit shall comply with the requirements set forth in § 72.49 and 40 CFR part 74, in addition to the statement in § 72.40(b), and the information requirements of § 72.31.

(d) The designated representative for multiple units with a common-stack shall comply with the requirements set forth in § 72.50, in addition to the statement in § 72.40(b), and the information requirements of § 72.31.

(e) The designated representative for a new unit shall comply with the information requirements set forth in § 72.45, in addition to the statement in § 72.40(b), and the information requirements in § 72.31.

(f) The designated representative shall specify the calendar year(s) during which each compliance option selected shall apply.

(g) If, by the time of applying for a permit, the source has not reached a firm decision about which compliance option(s) authorized under this part the affected unit will employ, the designated representative may, subject to subpart D, propose one or more Acid Rain compliance option in the proposed compliance plan for conditional approval. To activate a conditionally-approved compliance option, the designated representative shall notify the Administrator of the source's decision that the conditionally-approved compliance option will actually be pursued. No further review or revision of the permit shall be required. No conditionally approved compliance option shall become effective unless and until the designated representative activates the option by notifying the Administrator. In order for a conditionally-approved compliance option to apply to a unit during any calendar year the deadline, if any, for notifying the Administrator of a decision to activate the option specified in subpart D shall apply. The notification shall specify, in accordance with subpart D, whether the compliance option activation is sought for the current calendar year or for the following calendar year.

§ 72.33 Binding effect of acid rain program permit applications and proposed compliance plans.

As provided in section 408 of the Act, each Acid Rain program permit application and compliance plan shall be binding on the owners and operators of the affected source and the affected unit(s) covered by the permit application and proposed compliance plan, to the extent the application and plan provisions are consistent with title IV and the Acid Rain program requirements, beginning on the date of submission, unless and until the submission is superseded by a proposed, initial, or final Acid Rain permitting decision, including a determination of incompleteness or a disapproval.

Subpart D—Acid Rain Compliance Options

§ 72.40 General.

(a) Applicability. (1) This subpart shall apply to each affected source required to submit an Acid Rain permit application and proposed compliance plan pursuant to this part, and to each affected unit at an affected source.

(2) Each proposed compliance plan submitted pursuant to § 72.32 shall specify one or more of the Acid Rain compliance options specified in this subpart (§ 72.40(b)—§ 72.50), for each affected unit at the source by including the appropriate standard form provided in appendix C of this part and by submitting such other information required by this subpart for the option selected.

(b) Standard compliance. (1) The requirement in Section 408 of the Act and under subpart C of this part to have a compliance plan shall be deemed satisfied by a certification by the designated representative of an affected unit that the unit will meet the applicable emissions limitation requirements as set forth in the permit application and the proposed compliance plan in a timely manner.

(2) If the designated representative of any affected unit is selecting the standard compliance option only, the designated representative shall so indicate by checking the appropriate box on the Acid Rain permit application form, SF# 7231A in appendix C of this part.

(c) In the case of sulfur dioxide, regardless of the compliance option chosen, the plan shall certify that the designated representative will hold allowances or properly submit allowances for recordation as of the allowance transfer deadline, in the Allowance Tracking System compliance subaccount for the unit, established pursuant to 40 CFR part 73, not less than the total annual emissions of sulfur dioxide from the unit.

(d) In addition to the standard compliance option, the designated representative may select one or more of the compliance options specified in § 72.48 for the affected unit by following the procedures specified in those sections.

§ 72.41 Phase I substitution plans.

(a) Applicability. This section shall apply during Phase I only to existing units listed in appendix A or B of this part, and to the designated representative, the owners, and operators of any such units seeking to designate the appendix B unit as a substitution unit, for the purposes of meeting the appendix A unit's Phase I sulfur dioxide emissions reduction obligations by the distribution of allowances between the two units, where the appendix B unit is under the control of the same designated representative as the appendix A unit for which the proposed substitution plan is submitted.

(b)(1) The designated representative for a Phase I affected unit listed in appendix A may include in the unit's Acid Rain permit application and proposed compliance plan, a proposal to reassign, in whole or in part, the appendix A unit's Phase I sulfur dioxide emissions reduction requirements to one or more appendix B substitution unit.

(2) The designated representative may reassign all or part of the sulfur dioxide reduction requirements of a single appendix A unit or of multiple appendix A units:

(i) To a single substitution unit, or

(ii) To multiple substitution units.

(3) A reassignment of the emissions reductions requirements of one or more appendix A units to one or more substitution units shall ensure that not less than the combined total of the emissions reductions that would be required of the appendix A units in the absence of the plan, is achieved by the substitution unit(s).

(4) A substitution plan submitted pursuant to a common-stack plan in accordance with § 72.50 shall not be required to propose a reassignment of emissions reductions pursuant to paragraphs (b)(1)–(b)(3): *Provided* That the substitution plan meets the other requirements of this section.

(5) The designated representative may use a substitution unit as the control unit in a Phase I Extension plan:

Provided That the plan meets the requirements of this section and § 72.42.

(c) Special procedures. (1) A substitution plan shall only be effective during Phase I (January 1, 1995 through December 31, 1999), may become effective at any time during Phase I, and once a substitution plan has been approved and becomes effective it shall remain effective until the end of Phase I, unless a termination date is specified in the approved plan, or unless subject to paragraph (c)(2) of this section the plan is terminated pursuant to § 72.303 (administrative permit amendment).

(2) No substitution plan shall be terminated before the end of Phase I, nor any substitution unit under the plan be de-designated, unless allowances equivalent in number and compliance use date to those allocated pursuant to the plan for all units governed by the plan for the remainder of Phase I are surrendered. Such surrender shall be effected by the recordation of such allowances, pursuant to 40 CFR part 73, subparts C and D, in the Allowance Tracking System account(s) of such unit(s), and the deduction of such allowances pursuant to 40 CFR 73.35(g).

(3) No substitution plan under which the substitution unit also serves as a Phase I Extension control unit shall be terminated, nor shall such substitution unit be de-designated, before the end of Phase I, December 31, 1999.

(d) Contents of substitution plan. (1) General information. Each substitution plan contained in the permit application shall include the following information, using SF# 7241 in appendix C of this part:

(i) Identification of each unit proposed to be governed by the substitution plan, including each appendix A unit, and each proposed substitution unit;

(ii) The proposed date the substitution plan, if approved, would become effective (if other than January 1, 1995); or

(iii) The proposed date, if known, the substitution plan, if approved, would terminate (if prior to December 31, 1999);

(iv) Documentation, to the satisfaction of the Administrator, that the annual tonnage limits proposed in the substitution plan will, in total, achieve the same or greater annual emissions reduction than would have been achieved by the appendix A unit and the substitution unit or units without such substitution. Such documentation shall include the following calculations, using SF# 7241 in appendix C of this part:

(A) Calculation of the required annual emissions reductions (in tons per year) without a substitution plan for each appendix A unit governed by the proposed substitution plan as follows:

(*1*) Baseline × the lesser of actual or allowable 1985 emissions rate for sulfur dioxide/2000 = Tons sulfur dioxide 1985

(*2*) Tons sulfur dioxide 1985 − Appendix A unit's basic allocation = Phase I unit's required annual emissions reduction (in tons per year) without plan

(B) Calculation of the required annual emissions reductions (in tons per year) without a substitution plan for each appendix B substitution unit governed by the proposed substitution plan as follows: [Baseline × lesser of actual or allowable 1985 emissions rate/ 2000]—[Baseline × the most stringent Federally enforceable allowable emissions rate in the year that the application is submitted [1] = the substitution unit's annual required emissions reductions (in tons per year) without the plan.

(C) Calculation of the proposed annual sulfur dioxide emissions reductions (in tons per year) that will be achieved by each appendix A unit under the proposed substitution plan as follows: Tons sulfur dioxide 1985 (as calculated in subsection (d)(1)(iv)(A)(*1*) of this section—annual projected sulfur dioxide emissions (in tons per year) under the proposed plan = annual reductions (in tons per year) that will be achieved by the Appendix A unit.

(D) Calculation of the proposed annual sulfur dioxide emissions reductions (in tons per year) required to be achieved by each substitution unit under the proposed substitution plan as follows: [Baseline × the lesser of actual or allowable 1985 emissions rate/ 2000]—[proposed annual sulfur dioxide emissions (in tons per year) required to satisfy the proposed plan [2] = proposed annual reductions (in tons per year) required to satisfy the plan for the substitution unit.

(E) Calculation showing that the total annual sulfur dioxide emissions reductions (in tons per year) under the proposed substitution plan will be equal to or greater than the total annual sulfur dioxide emissions reductions (in tons per year) that would have been achieved without the plan as follows: [The sum total for (d)(i)(iv)(C) (in tons per year) for a given year for all appendix A units governed by the proposed substitution plan plus the sum total for (d)(1)(iv)(D) (in tons per year) for a given year for all substitution units governed by the proposed substitution plan] greater than or equal to [the sum total for (d)(1)(iv)(A)(*2*) (in tons per year) for a given year for all appendix A units governed by the proposed substitution plan plus the sum total for (d)(1)(iv)(B) (in tons per year) for a given year for all substitution units governed by the proposed substitution plan.

(v) If a substitution unit is located at another source, a complete permit application for that source; and

(vi) Such other information as the Administrator may require.

(2) Emissions Standards, Schedules, and Test Methods for Demonstrating Compliance. (i) Emissions Limitation/ Compliance Deadline. Each proposed substitution plan shall provide:

(A) The proposed annual allowance allocation distribution for the appendix A and substitute units; and

(B) That it shall be a violation of the Act for any unit governed by the substitution plan to fail in any year to achieve the sulfur dioxide emissions reductions specified in paragraphs (d)(1)(iv) (C) and (D) of this section, unless the designated representative of such unit holds allowances in the Allowance Tracking System compliance subaccount for the unit as of the allowance transfer deadline as provided in 40 CFR part 73, equal to or greater than the sulfur dioxide emissions for that unit for that calendar year.

(ii) Test method(s). Compliance with the emissions reduction requirements and limitations specified in the substitution plan shall be determined using the emissions monitoring system certified, and records and reports submitted in accordance with 40 CFR part 75. Each substitution plan shall provide that each unit governed by the substitution plan shall comply with all monitoring, recordkeeping, and reporting requirements as specified in 40 CFR part 75 and in the unit's monitoring plan.

(3) Recordkeeping Requirements. Each substitution plan shall require that each unit governed by the plan shall comply with the standard recordkeeping requirements specified in this part and 40 CFR parts 73–78.

(4) Compliance Certification Reporting Requirements. Each substitution plan shall require that the designated representative for each unit governed by the plan shall comply with the standard compliance certification reporting requirements specified in subpart K of this part.

(e) Administrator's Action on Proposed Substitution Plan. (1) The Administrator shall act on a proposed substitution plan in accordance with the

[1] If the most stringent Federally enforceable allowable emissions rate for the substitution unit in the year that the application is submitted is the same as or less stringent than the lesser of the actual or allowable 1985 emissions rate for that unit, the reductions required of the substitute unit without the plan are deemed to be zero.

[2] The proposed annual sulfur dioxide emissions required to satisfy the proposed plan are the minimum emissions required, not the actual projected emissions if they are less than what is required to satisfy the plan.

procedures and deadlines specified in subpart G, and shall approve such plan if it fulfills the requirements of this section.

(2) The Administrator may approve a proposed substitution plan, in whole or in part, and with such modifications or conditions as may be consistent with the orderly functioning of the allowance system, if the proposal as modified or conditioned will ensure the emissions reductions contemplated by title IV of the Act and this part.

(3) If a substitution plan meets the requirements of this section and is approved by the Administrator:

(i) Each substitution unit governed by the plan shall be a Phase I affected unit under the Acid Rain program, from the date on which the substitution plan takes effect until the date on which the plan terminates. Each source with any such unit shall be an affected source.

(ii) Each affected unit under a substitution plan shall be subject to the following requirements:

(A) The emissions monitoring planning, certification, recordkeeping and reporting requirements of this section and 40 CFR part 75;

(B) The nitrogen oxides requirements of 40 CFR part 76 (including that for any such unit that is (*1*) a tangentially fired boiler, or (*2*) a dry-bottom wall-fired boiler (other than units applying cell burner technology), the exemption in 40 CFR part 76 from any more stringent Phase II nitrogen oxides emissions limitations than those required to be met in Phase I, if such more stringent limits are set by the Administrator by January 1, 1997, shall apply);

(C) The sulfur dioxide allowance allocation and emission limitation requirements specified in the plan provided in paragraph (d) of this section as approved; and

(D) The utilization requirements specified in § 72.43 (reduced utilization plans), and in § 72.409.

(iii) The Administrator shall issue permits to each affected source with an appendix A or substitution unit, in accordance with the approved substitution plan and the requirements of this part.

(iv) Allowance allocations. The Administrator shall allocate allowances to the unit accounts for each appendix A and substitution unit pursuant to 40 CFR part 73 and in accordance with the approved substitution plan as follows:

(A) For each appendix A unit for each calendar year the substitution plan is in effect, allowances equal to the basic allowance allocation plus the difference between the basic allocation for that unit and the projected annual sulfur dioxide emissions (in tons per year) pursuant to subsection (d)(1)(iv)(C) of this section as modified by the Administrator under the approved substitution plan.[3]

(B) For each substitution unit for each calendar year the substitution plan is in effect, allowances equal to the proposed annual sulfur dioxide emissions required to satisfy the proposed plan pursuant to paragraph (d)(1)(iv)(D) of this section as modified by the Administrator under the approved substitution plan.

(C) In no event shall allowances be allocated in excess of: [the sum total of the appendix A unit's allocations authorized without the substitution plan] plus [the sum total of the product of each substitution unit's baseline and the most stringent federally enforceable allowable emissions rate for each unit for the year that the application is submitted.

(4) If a proposed substitution plan does not meet the requirements of this section, the Administrator shall disapprove it and shall allocate allowances to the appendix A unit or units in accordance with 40 CFR part 73.

(f) Prohibitions. (1) It shall be a violation of the Act for any unit subject to a substitution plan to violate any provision of the plan as provided in paragraph (d) of this section, or to violate a provision of paragraphs (c) (1) through (3) of this section.

(2) The owners, operators, and designated representative of an appendix A or substitution unit governed by a plan approved by the Administrator under this section shall be liable for any violation of this section or the plan at that or any other unit governed by the substitution plan; including liability for fulfilling the obligations specified in 40 CFR part 77 and section 411 of the Act. Any such violation shall be a violation of the Act.

(3) Each proposed and approved substitution plan under this section shall contain the prohibitions of paragraphs (f) (1) and (2) of this section.

§ 72.42 Phase I extension plans.

(a) Applicability. (1) This section shall apply during Phase I only to any existing affected unit, and to the designated representative, owners, and operators of any such unit, seeking a 2-year extension of the deadline for meeting the Acid Rain program Phase I sulfur dioxide emissions reduction requirements, pursuant to section 404(d) of the Act, including extension allowance allocations under that authority.

[3] In no instance shall the allowance allocation for an appendix A unit pursuant to a substitution plan be less than such unit's basic allowance allocation.

(2) This section shall apply to any affected unit listed in appendix A of this part identified in a plan submitted pursuant to this section for which a Phase I extension is sought, and to any unit listed in appendices A or B designated in a plan submitted under this section as a control unit.

(b)(1) The designated representative for any appendix A affected unit, as provided in paragraph (a) of this section, may submit a proposed plan to the Administrator in accordance with this section for a 2-year extension of the appendix A unit's January 1, 1995 deadline for meeting the sulfur dioxide requirements, *Provided* that, notwithstanding any such extension:

(i) The designated representative shall hold allowances in each of the 2 years of the extension period, in the Allowance Tracking System compliance subaccount for each unit governed by the extension plan, in an amount not less than the unit's emissions for the year; and

(ii) The proposed plan certifies:

(A) That the appendix A unit for which the extension is sought will install on or after November 15, 1990 but not later than December 31, 1996, a qualifying Phase I technology; or

(B) That the appendix A unit for which the extension is sought will transfer its Phase I emissions reduction requirements, in accordance with paragraph (c)(2) of this section, to a control unit designated in the proposed extension plan that will install and operate a qualifying Phase I technology on or after November 15, 1990 but not later than December 31, 1996; and

(C) The proposed plan meets the requirements of paragraph (e) of this section.

(2) Transfer plans. In the case of a compliance plan that proposes a transfer of an appendix A affected unit's emissions reduction obligations to a control unit, the compliance plan shall govern operations at each unit included in the transfer plan, and shall specify the emissions reduction requirements imposed on each transfer and control unit pursuant to this section.

(3) If the transfer and control units designated in a proposed Phase I Extension plan are not located at the same source, the designated representative of each source shall sign and certify the proposed plan and shall include the proposed plan with the permit application for each source.

(4) The designated representative may propose to transfer the emissions reduction requirements of a single appendix A affected unit or of multiple appendix A affected units, in whole or in part to one or more control unit;

Provided That all control units governed by a plan are located at a single source; and *Provided further*, That the control unit or units shall not be committed to achieve the emissions reduction requirements of one or more transfer units in excess of the difference between the control unit's basic allowance allocation (or the allocation authorized pursuant to § 72.41 in the event the control unit is a substitution unit), and the emissions that would be achieved at 90% control by installing the qualifying Phase I technology;

(5) A substitution unit, designated in a plan under § 72.41, or a compensating unit, designated in a plan under § 72.43, may be designated as the control unit in a proposed Phase I Extension plan; *Provided* That the Administrator determines that the unit meets the requirements for substitution units at § 72.41 or for reduced utilization compensating units at § 72.43, in addition to the requirements for control units of this section.

(c) Each Phase I Extension plan submitted under this section shall be considered in order of receipt as determined in accordance with subpart L.

(d) Early ranking procedure. The order of receipt of a proposed Phase I Extension plan as provided in paragraph (e) of this section, shall be determined, prior to submission of a complete permit application and proposed compliance plan as required by subpart C of this part, pursuant to the early ranking procedure specified in subpart L.

(e) Contents of proposed Phase I extension plans. The designated representative for any unit seeking a Phase I extension shall submit a ranking application, and shall include with each permit application a proposed Phase I extension plan, using SF# 7242A in appendix C of this part, containing the following information:

(1) General information. (i) Identification of the unit(s) proposed for designation as the control unit(s) in the Phase I extension plan;

(ii) Identification of the appendix A unit(s), if any, that will transfer all or any part of their emissions reduction obligations to the control unit(s) identified pursuant to paragraph (e)(1)(i) of this section;

(iii) For each unit in the plan, the average annual total tonnage of sulfur dioxide in calendar years 1988 and 1989 calculated using the information filed on EIA Form 767 and listed in appendices A and B not to exceed the annual tonnage equivalent of the most stringent federally enforceable allowable emissions rate for those years for sulfur dioxide.

(iv) The projected uncontrolled emissions in tons per year for each control unit for 1995 and 1996, calculated for each year as follows: ((Projected annual utilization (in mmBtu) as reported on EIA Form 767 filed in the year in which the Phase I extension application is made) × (the lesser of the most stringent federally enforceable allowable emissions rate for sulfur dioxide (in lbs/mmBtu) at the time of application or the emissions rate based on the sulfur content of the fuel to be used) ÷ 2000)

(v) Projected controlled emissions in tons per year for each control unit for 1997, 1998, and 1999 calculated as follows: ((Projected utilization (in mmBtu) as reported on EIA Form 767 filed in the year in which the Phase I Extension application is made) × projected emissions rate (in lbs/mmBtu) not to exceed the most stringent federally enforceable allowable emissions rate for sulfur dioxide at the time of application) ÷ 2000

(vi) Projected emissions in tons per year for each transfer unit in the plan for 1995 through 1999, calculated as follows: ((Projected utilization (in mmBtu) as reported on EIA Form 767 filed in the year in which the Phase I Extension application is made) × projected emissions rate (in lbs/mmBtu) not to exceed the most stringent Federally enforceable allowable emissions rate at the time of application) ÷ 2000

(vii) Documentation that the annual emissions reduction obligations transferred to each control unit governed by the Phase I extension plan do not exceed those authorized under the requirements of this section, as follows:

(A) For each control unit, the basic allowance allocation (or allocation authorized under § 72.41 in the event the control unit is a substitution unit) minus the annual emissions in tons per year that would occur at the unit at 90% control using a qualifying Phase I Extension technology, equals the total annual emissions reduction obligation that a control unit may assume for transfer units authorized to be accounted for by the control unit.

(B) For each transfer unit governed by a Phase I Extension plan, the designated representative shall specify the tons per year of sulfur dioxide emissions for 1995 and 1996 from that unit for which it will receive allowances from the Phase I Extension reserve above its basic allocation not to exceed the tonnage amount that will be accounted for by each control unit in the plan. The sum total of the annual tons above basic allocations specified for all the transfer units under the plan pursuant to this paragraph shall not exceed the total annual emissions reduction obligation assumed by all the control units in the plan calculated pursuant to paragraph (e)(1)(vii)(A) of this section.

(C) For each transfer unit specify the total tons of emissions reduction obligations that will be accounted for by each control unit's annual emissions reductions below its basic allowance allocation.

(viii) For each unit in the Phase I Extension plan, the proposed number of allowances from the Phase I Extension reserve to be allocated for each year and the sum total of Phase I Extension reserve allowances requested for all units in the plan for 1995 through 1999.

(2) Documentation, standards, schedules, and test methods for demonstrating compliance. (i) Technology standard—90% control requirement. Each proposed Phase I Extension plan shall include the following:

(A) A copy of a fully executed contract, which may be contingent only upon the Administrator approving the proposed extension plan, for the design engineering, construction, and installation by not later than January 1, 1997, of qualifying Phase I extension technology at the control unit(s), governed by the plan including any purchase order.

(B) A description of the technology, including:

(*1*) The type of technology;

(*2*) A vendor guarantee of the design sulfur dioxide removal efficiency and the characteristics of the fuel or range of fuels for which the technology is designed, including a certification by the vendor stating that the technology will achieve at least 90% removal of sulfur dioxide for the type of fuel and range of fuels that will be used at the control unit; *Provided* That in no event shall a vendor guarantee be a defense against a control unit's failure to achieve 90% control of sulfur dioxide; and

(*3*) A schedule of compliance, including dates for the following increments: Start design engineering; complete design engineering; start construction; complete construction; start-up testing; commence operation (not later than December 31, 1996); and periodic operation and maintenance of the control equipment.

(C) A schedule for start-up and periodic technology compliance demonstrations, as follows:

(*1*) Post-combustion control technology start-up performance testing. Each proposed Phase I Extension plan shall require that not later than ninety days after start-up of post-combustion

qualifying Phase I control technology, the owners or operators of the unit shall conduct a performance test as specified in § 75.12(c), and the designated representative shall report the results of such test to the Administrator with the quarterly emissions monitoring report for the quarter during which the test was conducted in accordance with Subpart K of this part. The results of such test shall serve as a demonstration of the technology's ability to achieve 90% control. (See § 72.42(g) regarding failure to demonstrate 90% control.)

(2) Post-combustion control technology annual demonstration. Each proposed Phase I Extension plan shall require that each calendar year beginning in the year the unit commences operation of the qualifying Phase I control technology, through 1999, the designated representative shall establish the technology's ability to achieve 90% control, through annual performance tests in accordance with 40 CFR 75.12(d). The results of the annual recertification test shall be reported to the Administrator, with the quarterly report for the fourth quarter in accordance with subpart K of this part. (See § 72.42(g) regarding failure to demonstrate 90% control.)

(3) Pre-combustion or combustion technology testing. Where the designated representative proposes to meet the 90% control requirement with a technology that removes sulfur dioxide through a chemical reaction in the combustion process, each proposed Phase I Extension plan shall specify start-up and annual demonstration tests of 90% control of sulfur dioxide to be performed based on a method proposed by the applicant and approved by the Administrator on a case-by-case basis. In such case, the showing of 90% control shall be in comparison to the concentration of sulfur dioxide in the emissions of a new conventional boiler using fuel with the same sulfur content.

(*4*) Each proposed Phase I Extension plan shall require that the owners and operators and designated representative of the unit conduct such additional tests, and report such additional test results as the Administrator determines is necessary in support of this subsection.

(ii) Emissions standards. (A) Each proposed Phase I Extension plan shall include the following Acid Rain program emissions limitations and compliance deadlines:

(*1*) The proposed total annual allowance allocation for each unit governed by the plan;

(*2*) A requirement that, during the 2 year extension period and thereafter, the designated representative shall hold allowances in the Allowance Tracking System compliance subaccount for each affected unit governed by the plan as of the allowance transfer deadline, as provided for in 40 CFR part 73, not less than the total annual sulfur dioxide emissions from the unit.

(*3*)(*i*) A requirement that each control unit shall not be subject to the nitrogen oxides emissions limitation of 40 CFR part 76 until the unit shuts down to install the qualifying Phase I technology, and

(*ii*) A requirement that beginning on the date on which the control unit is removed from operation to install the qualifying Phase I technology, each control unit governed by the extension plan shall comply with the applicable Phase I nitrogen oxides emissions limitation set forth in 40 CFR part 76;

(*4*) A requirement that during the extension period and thereafter, each transfer unit governed by the extension plan shall comply with the applicable Phase I nitrogen oxides emissions limitation set forth in 40 CFR part 76; and

(*5*) A requirement that, as provided for in section 404(d)(7) of the Act, after January 1, 1997 no control unit or transfer unit shall emit sulfur dioxide in excess of the annual tonnage limitation specified in the Phase I Extension plan pursuant to paragraphs (e)(1)(v) and (e)(1)(vi) (for 1997–1999) of this section, as approved. Even if the designated representative holds allowances in the unit's Allowance Tracking System compliance subaccount to cover such unit's emissions for the year for purposes of 40 CFR part 77, the Administrator shall deduct allowances equal to such exceedances of the extension plan limitation from the unit's annual allowance allocation in the following calendar year.

(B) Emissions limitation test methods and emissions monitoring. Each Phase I Extension plan shall include an emissions monitoring plan as required by 40 CFR part 75, for each unit governed by the plan, and a certification that continuous emissions monitoring systems are, or will be not later than November 15, 1993, operational and certified by the Administrator on each Phase I extension control or transfer unit, as required for Phase I units by 40 CFR part 75.

(C) Recordkeeping requirements. Each Phase I Extension plan shall require that records demonstrating compliance with the plan including records demonstrating compliance with any performance standard or scheduled increment of progress throughout Phase I be maintained in accordance with § 72.10. Such records shall include emissions monitoring records maintained in accordance with this part and 40 CFR part 75.

(D) Compliance certification reporting requirements. Each Phase I Extension plan shall require the submission by the designated representative on behalf of the owners and operators of each affected source with a unit governed by the plan, of compliance certification reports in accordance with this section and subpart K, evidencing each unit's compliance with the requirements of the plan.

(f) Administrator's Action on Ranking Applications and Proposed Phase I Extension Plans. (1) The Administrator shall review and act on each early ranking application and each proposed Phase I Extension plan in accordance with the plan's order of receipt as established by the early ranking procedure in subpart L. The Administrator may approve an early ranking application submitted under subpart L, or an extension plan submitted under this subpart in whole or in part, and with such modifications or conditions as may be necessary, consistent with the orderly functioning of the allowance system, and to ensure the emissions reductions contemplated by title IV; *Provided* That no application or proposed plan shall be approved once the allowance reserve established as provided in paragraph (f)(2) of this section has been fully committed. Where the application or proposed plan meets the requirements of this section, the Administrator shall designate each unit governed by the application or proposed plan as an affected Phase I extension transfer or control unit, as applicable.

(2) In order to determine the number of Phase I extension ranking applications or proposed plans eligible for approval and conditional award of allowances from the Phase I extension allowance reserve established pursuant to section 403(a)(2) of the Act at subpart A, 40 CFR part 73, and to determine the number of uncommitted allowances remaining available in the reserve after each application or plan is acted upon, the Administrator shall act on each early ranking application and proposed plan by reducing the total number of uncommitted allowances remaining available in the reserve by the total number of allowances calculated for the application or plan according to paragraph (f)(3) of this section, until either no uncommitted allowances remain available in the reserve for further conditional award, or all proposals have been acted on. If no uncommitted allowances remain available in the allowance reserve before all applications or plans have

been acted on by the Administrator, any pending application or plan shall be conditionally disapproved.

(3) Allowance awards and allocations and removal of conditions. Each appendix A unit covered by an Early Ranking application submitted under subpart L or a proposed Phase I Extension plan submitted under this section shall receive its basic allowance allocations during Phase I. Each appendix B unit covered by a ranking application or proposed Phase I Extension plan shall be eligible for basic allowance allocations during Phase I, as determined by the substitution plan provisions of section 404(b) and (c) of the Act and § 72.41 of this part. In addition to the basic allowance allocations, the Administrator shall calculate and conditionally award allowances from any allowances remaining in the Phase I Extension allowance reserve to each unit governed by an Early Ranking application submitted pursuant to subpart L of this part, or proposed Phase I Extension plan meeting the requirements of this section, as follows:

(i) For calendar year 1995, the Administrator shall conditionally award allowances from the Phase I extension allowance reserve to each eligible Phase I extension control and transfer unit governed by the application or proposed plan, equal to the difference between:

(A) The lesser of the unit's average annual emissions in calendar years 1988 and 1989 (calculated as provided in paragraph (e)(iii) of this section), or its projected emissions tonnage for calendar year 1995 (calculated as provided in paragraph (e)(iv) of this section), and

(B) The product of the unit's baseline multiplied by an emissions rate of 2.50 lbs/mmBtu, divided by 2,000.

(ii) For calendar year 1996, the Administrator shall conditionally award allowances from the Phase I extension allowance reserve to each eligible Phase I extension control and transfer unit governed by the application or proposed plan, following the reductions from the reserve for such unit provided in paragraph (f)(3)(i) of this section, equal to the difference between:

(A) The lesser of the unit's average annual emissions in calendar years 1988 and 1989 (calculated as provided in paragraph (e)(iii) of this section), or its projected emissions tonnage for calendar year 1996 (calculated as provided in paragraph (e)(iv) of this section), and

(B) The product of the unit's baseline multiplied by an emissions rate of 2.50 lbs/mmBtu, divided by 2,000.

(iii) The reserve allowances conditionally awarded to a Phase I extension control or transfer unit for use in 1995 and 1996 pursuant to paragraphs (f)(3)(i) and (ii) of this section, when combined with the basic allowance allocations for each unit, shall in no instance exceed the tonnage equivalent of the most stringent Federally enforceable emissions limitation for sulfur dioxide for the unit for that year, where tonnage equivalent is calculated as follows: [(lbs/mmBtu $\times$ mmBtu for the year) $\div$ 2000].

(iv) For calendar years 1997, 1998, and 1999, the Administrator shall conditionally award allowances from the reserve to each eligible Phase I extension control unit governed by the ranking application or proposed Phase I Extension plan, following the reductions from the reserve for such unit provided for in paragraphs (f)(3)(i), (ii), and (iii) of this section, not to exceed the amount by which the product of each eligible control unit's baseline (in mmBtu) times an emissions rate of 1.20 lbs/mmBtu, divided by 2,000, exceeds the tonnage of emissions at the control unit that would result if the unit achieves 90% (or greater) control as specified under this section.

(v) Upon issuance of a Phase I permit pursuant to subpart C and D of this part which includes an approved Phase I Extension plan, reserve allowances which were conditionally awarded pursuant to paragraphs (f)(3)(i) through (iv) of this section above and subpart L of this part to any unit governed by the plan shall be conditionally allocated to the unit's Allowance Tracking System account.

(vi) At the end of each calendar year the condition on the reserve allowances, conditionally allocated pursuant to the preceding paragraph, shall be removed after the requirements of paragraph (g) of this section have been met.

(g) Annual remedy for failure to achieve 90% control. Failure to achieve 90% control during the 30-day start-up test required by paragraph (e)(2)(i)(C)(*1*) of this section shall be considered a violation of the Act provided that such violation may be cured by a 30-day retest demonstrating that 90% control has been achieved by December 31st of the year in which the initial start-up test was conducted. No Phase I extension allowances for that calendar year or future calendar years shall be allocated under the plan unless the unit demonstrates that 90% control has been achieved. Failure to demonstrate that 90% control is being achieved, during the annual recertification test required by paragraph (e)(2)(i)(C)(*2*) of this section, shall be considered a violation of the Act. In the event of any such violation, in addition to any other liability under the Act, including 40 CFR part 77 and section 404(d)(7), the full conditional allocation of Phase I Extension allowances for that calendar year shall not be allocated to the unit's Allowance Transfer System account. In the event of such violation, allowances shall be deducted from those conditionally allocated to the unit according to the following formula:

(1) Subtract the unit's actual annual average emissions rate from the emissions rate that would have been achieved with a 90% removal of sulfur dioxide;

(2) Multiply the difference between the two rates by the annual heat input (mmBtu's) from the unit; and

(3) Divide by 2000.

(h) Prohibitions. (1) It shall be a violation of the Act to operate any unit governed by a Phase I Extension plan in violation of any requirement of this section.

(2) The owners, operators, and designated representative of a control or transfer unit governed by a plan approved by the Administrator pursuant to this section shall be liable for any violation of said plan or this section at that or any other unit governed by the Phase I Extension plan; including liability for fulfilling the obligations specified in 40 CFR part 77 and section 411 of the Act. Any such violation shall be a violation of the Act.

(3) No Phase I Extension plan shall be terminated following issuance of an Acid Rain permit which includes such extension. The designated representative may, however, withdraw a Phase I Extension application at any time prior to issuance of the Phase I permit and approval by EPA of the extension plan.

(4) Each proposed and approved Phase I Extension plan shall contain the prohibitions of paragraph (h)(1)–(3) of this section.

§ 72.43 Phase I reduced utilization plans.

(a) *Applicability.* (1) The requirements of this section shall apply to:

(i) The designated representative, owners, and operators of any Phase I affected unit, including:

(A) Any unit in appendix A of this part, or

(B) Any other unit that becomes an affected unit during Phase I (including any unit designated as a compensating unit pursuant to this section or as a substitution unit pursuant to § 72.41);

(ii) Where the designated representative, owners, and operators of the Phase I affected unit referred to in

paragraph (a)(1)(i) of this section plan to:

(A) Reduce utilization of the Phase I affected unit below the unit's baseline to achieve compliance, in whole or in part, with the unit's Phase I emissions reduction requirements, and

(B)(*1*) Shift generation of the Phase I unit to a designated compensating unit that would not otherwise be affected during Phase I, including any appendix B or new unit; or

(*2*) Accomplish such reduced utilization through sulfur-free generation (including renewable energy generation), an energy conservation measure, or any improved unit efficiency measure.

(2) The requirements of this section shall not apply to the designated representative, owners, and operators of any Phase I affected unit that was utilized at a level below its baseline in any calendar year during Phase I as a result of economic dispatching, one or more forced outages, or to the extent the under-utilization was due to a system-wide downturn in sales. Nor shall the requirements of this section apply to the designated representative, owners, and operators of a Phase I affected unit that was utilized at a level below baseline in any year when the aggregate utilization of all Phase I units in the affected unit's utility system for that year was equal to or greater than the Phase I units' aggregate baseline, as reported pursuant to § 72.31(a)(6). In all such cases, however, the owners and operators of any such units shall be subject to the annual reporting requirements specified in § 72.402.

(3) The requirements of this section shall apply in the event the designated representative, owners, and operators of an affected unit decide during the course of any Phase I calendar year to rely on reduced utilization as a method of compliance. In that case, the designated representative shall submit a reduced utilization plan in accordance with this section not later than the annual compliance certification deadline for the year.

(b) *Special procedures.* (1) A reduced utilization plan shall only be effective during Phase I (January 1, 1995 through December 31, 1999), and may become effective at any time during Phase I. Once a reduced utilization plan has been approved and becomes effective, it shall remain effective until the end of Phase I, unless an earlier termination date is specified in the plan as approved or, subject to paragraph (b)(2) of this section, the plan is terminated pursuant to § 72.303 (administrative permit amendments).

(2) No compensating unit shall be de-designated before the end of Phase I unless the designated representative for the compensating unit surrenders allowances equivalent in number and compliance use date to those allocated for the compensating unit by the plan for the remainder of Phase I. Such surrender shall be effected by the recordation of such allowances, pursuant to 40 CFR part 73, subparts C and D, in the Allowance Tracking System account(s) of such unit(s), and the deduction by the Administrator of such allowances pursuant to 40 CFR 73.35(g).

(3) No reduced utilization plan that designates a compensating unit that also serves as a control unit in a Phase I Extension plan shall be terminated nor shall such unit be de-designated before the end of Phase I, December 31, 1999.

(c) *Contents of proposed plan.* (1) General Information. Each proposed reduced utilization plan contained in the permit application shall include the following information, using SF# 7243 of appendix C of this part:

(i) Identification of each Phase I unit that will be reducing utilization, and each designated compensating unit;

(ii) The extent to which such affected unit will rely on reduced utilization to comply with its Phase I emissions reduction requirements, including:

(A) The reduction in kilowatt hours (Kwh) resulting from the unit's reduced utilization, and the extent of planned reduced utilization at the unit below its baseline (in Btu's);

(B) The annual average sulfur dioxide and nitrogen oxides emissions rates (in lbs/mmBtu) expected at the unit reducing utilization during Phase I;

(C) Identification of the compensating generation planned, including:

(*1*) The facilities that will be providing the compensating generation;

(*2*) Documentation, in the case of compensating generation provided by a utility system other than the system in which the unit reducing utilization is located, of utility system directives, or power purchase or other contractual agreements governing the compensating generation provided by the other utility systems; and

(*3*) The extent of compensating generation that will be provided by any one compensating unit or sulfur-free generating facility (in Kwh).

(D) Documentation of the extent to which the generation decrease (in Kwh) resulting from the total reduced utilization (in Btu) at the Phase I unit will be accounted for by:

(*1*) Proposed kilowatt hour increases at compensating unit(s);

(*2*) Proposed kilowatt hour increases at sulfur-free generators;

(*3*) Expected kilowatt hour decreases at the Phase I unit due to improved unit efficiency at the Phase I unit; and

(*4*) Expected kilowatt hour decreases at the Phase I unit due to energy conservation in the unit's utility system.

(E) A certification that the reduced utilization, in combination with any other compliance option proposed to be used by the Phase I unit, will as a whole achieve compliance by the unit with its Phase I emissions reduction requirements;

(iii) The proposed date, if known, that the reduced utilization plan, if approved, would become effective (if other than January 1, 1995); or

(iv) The proposed date the reduced utilization plan, if approved, would terminate (if prior to December 31, 1999);

(v) For each compensating unit identified in the plan located at a different source (other than a sulfur-free generator), copies of the certified permit application pages, including a certificate of representation, relevant to the compensating unit;

(vi) In the case of plans relying on sulfur-free generation, energy conservation measures, or improved unit efficiency measures, a demonstration, to the Administrator's satisfaction as provided in paragraphs (c)(2) through (4) of this section, that the Phase I affected unit(s) for which the plan is submitted will achieve reduced utilization through such sulfur-free generation, energy conservation, or improved unit efficiency; and

(vii) Such other information as the Administration may require.

(2) *Sulfur-free generation plans.* Each proposed reduced utilization plan relying on sulfur-free generation (including generation provided by renewable energy generation) shall identify each generator that will provide such sulfur-free generation, using SF# 7243 in appendix C of this part, and shall include the documentation specified in subparagraphs (c)(1)(ii)(C), of this section.

(3) *Energy conservation plans.* Each proposed reduced utilization plan for a Phase I affected unit that plans to achieve reduced utilization using one or more energy conservation measure shall be submitted using SF# 7243 in appendix C of this part, and shall include:

(i) A description of each energy conservation measure that the unit's utility system will employ in the service area the unit serves, as determined in accordance with the EPA Conservation Verification Protocol provided for in 40 CFR part 73.

(ii) A forecast of the kilowatt hour savings expected from each energy conservation measure, and the effective life of each measure as provided in the EPA Conservation Verification Protocol provided for in 40 CFR part 73; and

(iii) A forecast of the reduced utilization that is expected to occur at the Phase I affected unit (in mmBtu) as a result of the kilowatt hour savings forecasted to result from each energy conservation measure.

(4) *Improved unit efficiency plans.* Each proposed reduced utilization plan for a Phase I affected unit that plans to achieve reduced utilization using one or more measures for improving unit efficiency as measured by improvements in the unit's heat rate (in Btu/Kwh), shall be submitted using SF# 7243 in appendix C of this part, and shall include:

(i) A description of each efficiency improvement measure the unit will employ;

(ii) A forecast of the kilowatt hour savings expected from each unit efficiency improvement measure the unit will employ; and

(iii) A forecast of the improvement in heat rate and the reduced utilization that is expected to occur at the unit as a result of each unit efficiency improvement measure the unit will employ including a forecast of the effective life of the measure.

(5) *Emissions limitation.* Each reduced utilization plan shall require each unit governed by the plan to comply with:

(i) The Acid Rain program emissions limitation requirements, as provided in § 72.54(b)(3)(v);

(ii) The emissions monitoring plan and emissions monitor certification requirements, as provided in § 72.31(c) and 40 CFR part 75;

(iii) The compliance certification reporting requirements of subpart K of this part and paragraph (c)(6) of this section below including the requirement to account for all under-utilization at the Phase I unit not contemplated by the reduced utilization plan for the unit, as provided in this section and in § 72.402 and § 72.409 of subpart K of this part; and

(iv) The requirement that the designated representative surrender allowances, calculated pursuant to the method specified in § 72.409(d) and 40 CFR 73.35, to account for the emissions attributable to the difference between the verified energy savings achieved during the fourth quarter of any calendar year and the estimate of fourth quarter savings submitted in the annual report, as provided in paragraph (c)(6)(ii)(A) and (B), of this section, to the extent the estimated savings were used to offset reduced utilization at the Phase I affected unit.

(6) *Compliance certification reporting*—(i) *Verification of energy conservation and improved unit efficiency.* Each reduced utilization plan relying on an energy conservation or improved unit efficiency measure, including any supply-side measure, shall require that the designated representative submit verification of improved heat rate (in Btu/Kwh) and reduction in heat input (in mmBtu) as well as energy savings achieved (in Kwh) from the measures including the date the measures went into effect, and account for reduced utilization as follows:

(A) *Annual Report.* (*1*) The designated representative shall submit with the annual compliance certification report required by subpart K of this part verification of improved heat rate (in Btu/Kwh) reductions in heat input (in mmBtu), and energy savings (in Kwh) achieved from energy conservation or improved unit efficiency through the third quarter of the calendar year (September 30) using the procedures specified in paragraph (c)(6)(i)(C) of this section.

(*2*) Based on the verified energy savings, improved heat rate, and heat input reductions achieved through the third quarter, as provided in subparagraph (d)(6)(i)(A)(*1*) of this section, the designated representative shall submit an estimate of improved heat rate (in Btu/Kwh), energy savings (in Kwh), and resulting reductions in heat input (in mmBtu) at the unit for the fourth quarter of the year (October 1–December 31).

(B) *Fourth quarter confirmation report.* Within 90 days after the end of the calendar year, the designated representative shall submit with the quarterly compliance certification report required by subpart K verification of the energy savings actually achieved during the fourth quarter of the year (in kilowatt hours) and resulting reductions in heat input (in mmBtu) at the unit, pursuant to the procedures set forth in the EPA Conservation Verification Protocol.

(C) The energy savings verifications of paragraphs (A) and (B) shall be certified by:

(*1*) An independent auditor using the procedures set forth in the EPA Conservation Verification Protocol for energy conservation measures, pursuant to 40 CFR 73.81(a); or

(*2*) If the utility is subject to the rate-making jurisdiction of a State regulatory authority that meets the least-cost planning (LCP) and net income neutrality (NIN) criteria set forth in 40 CFR part 73, the verification of energy savings from demand-side measures may be certified by the State authority with rate-making jurisdiction over the utility; or

(*3*) For supply-side measures, verification shall not require LCP or NIN, and verification of supply-side measures may be certified by any authority with rate-making jurisdiction over the utility; if the procedures described in subparagraphs (2) and (3) for certifying energy conservation would interfere with the unit's ability to comply with the compliance certification deadlines specified in paragraphs (A) and (B), of this section, the verification shall be made as provided in subparagraph (1). For the purposes of the energy savings verification procedures, all verified kilowatt hour savings in any calendar year from energy conservation measures then in effect shall be creditable towards reductions in utilization below baseline at Phase I affected units in that calendar year.

(D) The Administrator reserves the right to conduct independent audits of energy savings, or to otherwise ascertain that verifications provided by a Phase I affected source under this part are valid and correct.

(ii) *Verification of shifts to sulfur-free generators or to compensating units.* Each reduced utilization plan relying on increased generation at a sulfur-free generator or designated compensating unit shall require that the designated representative for the Phase I unit reducing its utilization demonstrate annually, using SF# 7243A in appendix C of this part, an increase in utilization (in mmBtu and Kwh) at the sulfur-free generator or designated compensating unit from its level of utilization prior to the shift in generation (after accounting for any system-wide growth in generation (in Kwh sales). If this increased utilization is less than the reduced utilization at the Phase I unit below its baseline, the provisions of § 72.409 shall apply.

(7) *Recordkeeping requirements.* Each reduced utilization plan shall require that each unit governed by the plan comply with the standard recordkeeping requirements specified in this part and 40 CFR parts 73 through 78. In addition, each such plan shall require that each unit governed by the plan maintain at the source all the documents, verifications, and demonstrations specified above.

(d) *Administrator's action on proposed plan.* (1) The Administrator shall act on a proposed reduced utilization plan in accordance with

Subpart G, and shall approve such plan if it fulfills the requirements of this section. The Administrator may approve a proposed reduced utilization plan in whole or in part and with such modifications or conditions as may be consistent with the orderly functioning of the allowance system. If a proposed reduced utilization plan does not meet the requirements of this section, the Administrator shall disapprove it and shall issue a permit and allocate allowances in accordance with the other sections of this part and 40 CFR part 73.

(2) *Compensating unit plans.* If a reduced utilization plan designating one or more compensating units meets the requirements of this section and is approved by the Administrator:

(i) Each unit governed by the plan, including each unit designated as a compensating unit, shall be a Phase I affected unit until the date on which the plan terminates, subject to all requirements under this part and 40 CFR parts 73 through 78 (including the requirement for the unit to hold allowances in its Allowance Tracking System compliance subaccount as of the allowance transfer deadline provided for in 40 CFR part 73 not less than the unit's sulfur dioxide emissions for the calendar year). Each source with a unit designated as a compensating unit shall be an affected source during Phase I.

(ii) Upon approval of a reduced utilization plan designating a compensating unit, the Administrator shall allocate allowances to such compensating unit in each calendar year of Phase I during which the reduced utilization plan is in effect beginning with the year the compensating unit is designated until the date on which the plan terminates, calculated as the product of the unit's baseline multiplied by the lesser of the unit's actual 1985 emissions rate or its allowable 1985 emissions rate, divided by 2,000.

(3) The Administrator shall issue permits to each affected source with a unit governed by an approved reduced utilization plan in accordance with the provisions of the plan and the requirements of this part. Phase I units governed by an approved utilization plan may bank all allowances freed-up by the approved reduced utilization.

(e) *Prohibitions.* (1) It shall be a violation of the Act for the owners, operators, or designated representative of any affected unit governed by a reduced utilization plan to operate any such unit except in accordance with the terms of the plan as approved by the Administrator pursuant to this section, or to fail to carry out any measure provided for in the plan, including any revisions to the plan made pursuant to subpart J of this part.

(2) It shall be a violation of the Act for any affected source or unit to emit sulfur dioxide in excess of the emissions limitations provided for in the approved reduced utilization plan unless the unit holds allowances in its Allowance Tracking System compliance subaccount as of the allowance transfer deadline in an amount not less than the unit's total annual emissions for the year.

(3) It shall be a violation of the Act for any appendix A unit subject to a reduced utilization plan to emit nitrogen oxides in excess of the emissions limitation applicable to that unit pursuant to 40 CFR part 76.

(4) The owners, operators, and designated representative of the original or compensating Phase I affected unit governed by a reduced utilization plan approved by the Administrator under this section shall be liable for any violation of said plan or of this section at that or any other unit governed by the reduced utilization plan; including liability for fulfilling the obligations specified in 40 CFR part 77 and section 411 of the Act. Any such violation shall be a violation of the Act.

(5) Failure to file a plan. (i) It shall be a violation of the Act and of this part for the owners, operators, and designated representative of any Phase I unit that reduces utilization in any calendar year as a method of compliance with the unit's Phase I emissions reduction obligations under the Acid Rain program to fail to submit a reduced utilization plan in accordance with this section.

(ii) Where a Phase I affected unit was under-utilized during a Phase I calendar year as compared to its baseline, the requirement to submit a reduced utilization plan meeting the requirements of this section shall be deemed not to be violated in that year to the extent that the designated representative demonstrates, in the annual report under § 72.402, that:

(A) The aggregate utilization for all Phase I units within the utility's system was equal to or greater than the aggregate baseline for the units; or

(B) The under-utilization was caused by a system-wide downturn in sales; provided that to the extent the percentage of under-utilization exceeds the percentage of system-wide downturn the presumption of this paragraph shall be rebuttable and shall not apply where the Administrator finds, based on clear and convincing evidence, that there is a violation of the reduced utilization planning requirements; or

(C) The under-utilization was caused by a forced outage at the unit; or

(D) The under-utilization is verified to have been caused by the use of energy conservation measures by the unit's utility system, unit efficiency improvements, or sulfur-free generation under a plan approved under this section; or

(E)(*1*) The unit was subject to, and operated during the year in accordance with, one or more Acid Rain compliance options provided in an approved compliance plan pursuant to Subpart D (including the standard compliance requirement to hold allowances in the unit's compliance subaccount as of the allowance transfer deadline in an amount not less than the unit's emissions for the year); and

(*2*) Operation of the unit under the compliance plan resulted in the unit holding sufficient allowances, as of the allowance transfer deadline, to cover sulfur dioxide emissions that the unit would have had but for the under-utilization; *Provided That* the presumption under this subparagraph shall be rebuttable and shall not apply where the Administrator finds, based on clear and convincing evidence, that there is a violation of the reduced utilization planning requirement.

(iii) Where a Phase I affected unit was under-utilized during a Phase I calendar year as compared to its baseline and to the extent the designated representative does not make the demonstrations specified in paragraph (e)(5)(ii) of this section with regard to the under-utilization, the Administrator shall determine on a case-by-case basis whether the reduced utilization planning requirements are violated. In making this determination, the Administrator will consider, in addition to any other relevant information demonstrated by the designated representative for the unit, the following indicators:

(A) Indicators that the under-utilization was not due to a failure to plan:

(*1*) The extent to which measures were taken at the unit to cut its emissions rate for the year to 2.5 lbs/mmBtu or less (e.g., the use of low-sulfur coal); and

(*2*) The extent to which such under-utilization is demonstrated to be due to changes in the unit's dispatch order in the utility system resulting from increases in the relative cost of generation at the unit (including increases due to the installation of pollution control equipment or other equipment changes at the unit, or at any other unit in the system, or changes in fuel supply), except to the extent such changes in dispatch order are attributable to the cost savings that

would accrue to the utility system from the banking of allowances that would have been consumed but for the under-utilization;

(B) Indicators of a failure to plan:

(*1*) That the under-utilization was due to a fundamental change in the unit's role within the utility system, including where a unit is shut down; and

(*2*) That the under-utilized unit did not pursue other compliance strategies sufficient to ensure compliance without reduced utilization.

(iv) Notwithstanding any demonstration under paragraph (e)(5), of this section, the designated representative, owners, and operators, of the under-utilized Phase I unit shall be subject to the annual reporting requirements of § 72.402.

§ 72.44 Phase II repowering extensions.

(a) *Applicability.* This section applies to:

(1) Each source with an existing affected unit that has actual 1985 emissions rates equal to or greater than 1.2 lbs/mmBtu.

(2) Each source with a new unit that will be a replacement unit, as provided in paragraph (b)(2), of this section, for an existing unit meeting the requirements of paragraph (a)(1) of this section.

(3) Each source with an oil and/or gas-fired unit that has been awarded clean coal technology demonstration funding as of January 1, 1991 by the Secretary of Energy.

(b)(1) The designated representative of any affected unit meeting the requirements of paragraph (a)(1) of this section may include in the unit's Phase II Acid Rain permit application and proposed compliance plan a Phase II repowering extension plan, to comply with the Phase II sulfur dioxide requirements of the Acid Rain program, that includes a demonstration that the unit will be repowered with a qualifying repowering technology.

(2) The replacement of an existing utility unit meeting the requirements of paragraph (a)(1) of this section with a new utility unit located at a different site using a qualified repowering technology, shall be treated as a repowering of the existing unit for purposes of this section, if:

(i) The replacement unit is designated in the proposed compliance plan to replace the existing unit; and

(ii) The existing unit will be permanently retired from service on or before the date on which the designated replacement unit commences commercial operation.

(c) *Special procedures—administrator's review of repowering technology.* (1) The designated representative of a unit meeting the requirements of paragraph (a) of this section seeking a repowering extension shall submit to the Administrator at any time before June 1, 1997, a petition requesting approval of a proposed repowering technology. The petition shall use SF# 7244A in appendix C of this part, and shall include the following information in accordance with the repowering technology demonstration protocol issued, and amended from time to time, by the Administrator:

(i) Identification and description of the technology; and

(ii) Vendor guarantee estimating the following performance characteristics of the technology:

(A) Percent removal of each pollutant which is one of the multiple pollutants being controlled;

(B) Emissions rate of each pollutant identified in (c)(1)(ii)(A) of this section;

(C) Overall generation efficiency;

(D) Information on the state, chemical constituents, and quantities of solid waste generated (including information on land-use requirements for disposal), and on the availability of a market to which any by-products may be sold; and

(E) If a repowering technology is not listed in the definition of a qualified repowering technology in § 72.2, a vendor guarantee demonstrating that the technology can meet the performance characteristics specified for non-listed technologies in § 72.2. (The existence of such guarantee shall not be a defense against the failure to meet the performance characteristics for non-listed technologies specified in § 72.2.)

(2) The Administrator shall review the petition and, in consultation with the Secretary of Energy, shall make a conditional determination on whether the technology is a qualifying repowering technology.

(3) No proposed repowering extension plan submitted with a permit application shall be approved by the permitting authority until the Administrator makes a conditional determination, in accordance with this subsection, of whether the technology is a qualified repowering technology. Notwithstanding the preceding sentence, a permitting authority may conditionally approve a proposed Phase II repowering extension plan, when issuing a permit for the source, subject to the determination of the Administrator required by this subsection.

(d) *Repowering permit process deadlines.* The designated representative of a unit applying for a repowering extension shall submit to the permitting authority using SF# 7244 in appendix C of this part, and in accordance with this subsection:

(1) A proposed compliance plan for repowering by January 1, 1996;

(2) If the proposed plan is submitted for conditional approval, as authorized by § 72.32(h), the designated representative shall notify the Administrator by no later than December 31, 1997, of the source's election to activate the plan. No notification to activate a proposed repowering plan shall be allowed to be filed after December 31, 1997.

(3) Upon activation of such plan, the plan shall be deemed binding on the unit's owners and operators.

(e) *Contents of proposed compliance plan.* (1) *General information.* Each proposed repowering extension plan submitted under this section shall include the following information, using SF# 7244 in appendix C of this part:

(i) Identification of the unit governed by the repowering proposal;

(ii) Each unit's Federally-approved State Implementation Plan sulfur dioxide emissions limitation;

(iii) Each unit's actual sulfur dioxide emissions rate for 1995;

(iv) A schedule for construction, installation, and commencement of operation of the technology that is as expeditious as practicable, with the following milestones:

(A) Complete design engineering;

(B) Remove unit from operation to install the qualified repowering technology;

(C) Start construction;

(D) Complete construction;

(E) Start-up testing;

(F) The date the existing unit will be shut down, in the case of a plan involving the repowering of a replacement unit at a separate site; and

(G) Commence commercial operation.

(v) A requirement that by not later than January 1, 2000, the designated representative shall submit to the Administrator and the permitting authority the following additional information:

(A) Satisfactory documentation of a preliminary design and engineering effort;

(B) A copy of an executed and binding contract for the majority of the equipment to repower such unit; and

(C) Any additional information specified by the Administrator when reviewing the technology information provided in paragraph (c) of this section.

(vi) A requirement that should the technology, demonstration, or information requirements of this section not be met, the approved repowering

extension shall be deemed null and void.

(vii) A requirement that not later than 60 days after the repowered unit commences operation at full load, the designated representative shall submit a report comparing actual hourly emissions of any pollutant regulated under the Act at the repowered unit and at the existing unit prior to repowering.

(viii) Shutdown notification. A requirement that the designated representative of the affected unit governed by an approved repowering plan shall notify the Administrator in writing, using SF# 7244B in appendix C of this part, 60 days in advance of the date on which the affected unit for which the extension has been granted is to be removed from operation to install the repowering technology (or to be replaced).

(ix) Information concerning the status of the repowering technology approval petition required pursuant to paragraph (c) of this section, including a copy of the approval, if granted, or any other determination of the Administrator the date the petition was filed with the Administrator; and if still pending any additional information required by the Administrator to be submitted.

(2) Repowering with a replacement unit. For plans proposing replacement of an existing utility unit with a new utility unit located at a different site using repowering technology each proposed repowering extension plan submitted under this section shall include, in addition to the information specified in paragraph (e)(1) of this section, the following information on SF# 7244 in appendix C of this part:

(i) Identification of the replacement unit, in accordance with paragraph (a) and (b) of this section;

(ii) Certification that the replacement unit will replace the existing unit;

(iii) Certification that the replacement unit has the same designated representative; and

(iv) Certification that the existing unit will be permanently retired from service on or before the date the designated replacement unit commences commercial operation.

(3) Each proposed repowering extension plan submitted under this section shall include the following information on the standards, compliance deadlines schedules, and test methods for demonstrating compliance that will apply to the units governed by the plan.

(i) Beginning in the year 2000 it shall be a violation of the Act for any unit with an approved repowering extension to emit sulfur dioxide in any calendar year in excess of the allowances held for use in that calendar year in the unit's Allowance Tracking System compliance subaccount as of the allowance transfer deadline, during the period of the repowering extension and, in the case of a replacement unit, beginning on the date the existing unit is permanently removed from operation.

(ii) It shall be a violation of the Act for any existing unit with an approved repowering extension or any replacement unit to emit nitrogen oxides annually in excess of the applicable limitation set pursuant to 40 CFR part 76 beginning on the date that the unit is removed from operation to install the repowering technology.

(iii) In no event shall any unit governed by a repowering extension plan be excused from compliance with any other requirement of the Act, including any National Ambient Air Quality Standards requirement, or State Implementation Plan, or New Source Performance Standard.

(iv) No repowering extension plan shall be terminated after December 31, 1999. The designated representative for a repowering unit may, however, withdraw and terminate the repowering extension plan at any time prior to December 31, 1999 using the administrative permit amendment procedures set forth at § 72.303.

(f) Permitting authority's action on proposed repowering extension plan. (1) Any proposed repowering extension plan that meets the requirements of paragraphs (a) through (d) of this section and subparts B and C of this part shall be approved by the permitting authority, subject to the Administrator's approval of the repowering technology, as provided in paragraph (c) of this section, above, authorizing an extension of the emissions limitation requirement compliance date for the existing unit governed by the plan from January 1, 2000, until the most expeditious date practicable that the unit can be removed from operation as demonstrated by the plan as approved but not later than December 31, 2003.

(2) Permit issuance. Based on a decision by the Administrator to conditionally approve a repowering technology, and a decision by the permitting authority in accordance with this section to grant an extension, the permitting authority shall issue a permit specifying the extension in the Acid Rain portion of the operating permit issued to the source and in the approved compliance plan under subpart I, together with the compliance schedule and other requirements necessary to ensure that the unit will meet the Phase II emission reduction requirements as provided in this section.

(3) Allowance allocation. (i) The Administrator shall allocate allowances to the affected unit for use during the repowering extension period approved under this section (including a pro rata allocation for any fraction of a year) equal to the affected unit's baseline multiplied by the lesser of the unit's most stringent Federally enforceable state implementation plan emissions limitation for sulfur dioxide in each year of the extension or its actual emissions rate for 1995, in lieu of any other allowance allocation that would otherwise be authorized under the Acid Rain program. Allowances allocated under this paragraph shall not be transferrable.

(ii) Effective on the date specified in the approved repowering plan as the date on which the affected unit for which the extension has been granted will be removed from operation to install the repowering technology or will be permanently removed from service for replacement, the original affected unit or replacement unit (if any) shall be subject to the emissions limitation requirements of the Acid Rain program including allowances for sulfur dioxide as follows:

(A) Beginning with the year or portion of the year in which the existing unit is removed from operation, allowances shall be allocated annually to the existing unit calculated as the product of the unit's baseline multiplied by 1.20 lbs/mmBtu, divided by 2,000, prorated according to the date the unit is removed from operation. Such allowances shall be transferrable.

(B) Notwithstanding the provisions of 40 CFR part 73, the allowances calculated as provided in paragraph (A)(f)(3)(ii) of this section shall be allocated annually to the designated replacement unit (if any), in lieu of any further allocations of allowances to the existing unit.

(4) Failed or delayed repowering projects. (i) If the designated representative of an existing unit granted an extension under this section demonstrates to the satisfaction of the Administrator and the permitting authority that the repowering technology specified in the approved plan for such unit was properly constructed and tested on such unit, but was unable to achieve the emissions reduction limitations specified in the plan and that it is economically or technologically infeasible to modify the technology to achieve such limits, such existing unit may be retrofitted or repowered with another clean coal or other available control technology. Notwithstanding the previous sentence,

no further extension of the Phase II emissions limitation deadline shall be authorized in such cases.

(ii) If at any time on or before December 31, 2003 the designated representative notifies the Administrator that the repowering project has failed, and the Administrator determines that there has been a good faith effort to properly design, construct, and test the repowering unit, it shall not be deemed a violation of the Act. Upon the determination that the repowering project at the unit has failed, the Administrator shall allocate allowances to such unit according to the Phase II allocations authorized by section 403 of the Act and 40 CFR part 73 for such unit.

(g) Effect of extension and prohibitions. A Phase II repowering extension shall not exempt the unit granted the extension from the obligation to comply with all of the requirements of title IV of the Act, and this part and 40 CFR parts 73–78, as if it were a unit subject to the Phase II compliance deadline as follows:

(1) Beginning in the year 2000 it shall be a violation of the Act for the designated representative, owner, or operator, of a repowered unit to fail to comply with the requirements of this section, or of any other regulations or permit requirements implementing this section.

(2) It shall be a violation of the Act to transfer any allowances allocated to a unit granted a repowering extension during the repowering extension period.

(3) Any unit that is granted an extension under this section shall not be eligible for a waiver under section 111(j) of the Act.

(4) No new unit that is designated as a replacement unit for an existing unit qualifying for an extension under this section and that is located at a different site than the existing unit shall receive an exemption from the requirements imposed under title I of the Act, including section 111 of the Act.

(5) The owners, operators, and the designated representative of a unit governed by a repowering extension plan approved by the permitting authority under this section shall be liable for any violation of this section or the plan at that or any other unit governed by the plan, including liability for fulfilling the obligations specified in 40 CFR part 77 and section 411 of the Act. Any such violation shall be a violation of the Act.

(6) Each proposed and approved repowering extension plan shall contain the prohibitions of paragraph (g)(1)–(5) of this section.

§ 72.45 New unit plans.

(a) *Applicability.* This section applies to Acid Rain permitting for any unit that:

(1) Is a new unit (i.e., a unit that commenced commercial operation on or after November 15, 1990, including any unit that serves a generator with a nameplate capacity of 25MWe or less, or is a simple combustion turbine); and

(2) Did not serve a generator with a nameplate capacity of greater than 25MWe before November 15, 1990, but serves a generator with a nameplate capacity of greater than 25MWe on or after November 15, 1990.

(b) *Emissions Limitation/Compliance Deadline.* (1) Upon the later of January 1, 2000 or the date of commencement of operation of any new unit specified in paragraph (a) of this section, each new unit shall be an affected unit subject to the Phase II requirements of the Acid Rain program, including the requirement:

(i) To hold allowances in the unit's Allowance Tracking System compliance subaccount as of the allowance transfer date, not less than the unit's sulfur dioxide emissions for the year, and

(ii) To comply with the applicable emissions limitations for nitrogen oxides set forth in 40 CFR part 76.

(2) To monitor emissions, beginning upon commencement of operation in accordance with the deadlines and procedures set forth in 40 CFR 75.11.

(3) Notwithstanding paragraph (b)(1) of this section, any new unit designated as a compensating unit pursuant to § 72.43, or subject to the common stack requirements as provided in § 72.50 shall be an affected unit subject to the Phase I requirements of the Acid Rain program, beginning on the date specified in those sections, and as provided in paragraphs (c) (3) and (4) of this section.

(c) *Permit Application Procedures and Deadlines.* (1) The designated representative of each source that includes a new unit, as provided in paragraph (a)(1) of this section, shall submit a Phase II Acid Rain permit application and new unit plan, on SF# 72200 and SF# 72200A in appendix C of this part, to the permitting authority not later than 24 months before the later of:

(i) January 1, 2000; or

(ii) The date on which the unit commences operation.

(2) The designated representative of each source that includes a unit, as provided in paragraph (a)(2) of this section, shall submit a Phase II permit application and new unit plan, on SF# 72200 and SF# 72200A in appendix C of this part, to the permitting authority not later than 24 months before the later of the date on which the unit commences operation to serve a generator with a nameplate capacity of greater than 25MWe or January 1, 2000.

(3) The designated representative of each source that includes a unit subject to this section, as provided in subsection (a), that is designated as a compensating unit in a reduced utilization plan pursuant to § 72.43, shall submit a Phase I permit application, using SF# 7231 and SF# 7231A in appendix C of this part, to the Administrator with such compliance plan in accordance with the deadlines specified in § 72.43. Any such unit shall be subject to the requirements and deadlines applicable to Phase I affected units, shall receive no allowances and shall be deemed to have a baseline of zero.

(4) The designated representative of each source that includes a unit subject to this section, as provided in paragraph (a) of this section, that utilizes a common stack with a Phase I affected unit shall submit, by the later of February 15, 1993 or 24 months before the unit commences operation, a common stack plan, as provided in § 72.50, for the unit and all other units at the source sharing the common stack. Except as provided in 40 CFR part 75 for such units, any such unit shall be subject to the requirements and deadlines applicable to Phase I affected units shall receive no allowances and shall be deemed to have a baseline of zero.

(d) *Contents of Phase II Acid Rain Permit Application and Compliance Plans*—(1) *General information.* Each unit subject to this section, as provided in paragraph (a) of this section shall submit all information required in the Phase II Acid Rain permit applications pursuant to § 72.31, using SF# 72200 and SF# 72200A in appendix C of this part.

(2) *Compliance schedule.* In addition to the information required of all Phase II units in the Phase II permit application, any unit subject to this section, as provided in paragraph (a) of this section, shall submit a compliance plan not later than 24 months before the later of January 1, 2000 or the date on which the unit commences operation.

(3) *Recordkeeping requirements.* Each unit subject to this section shall comply with all standard recordkeeping requirements of this part pursuant to § 72.51(i) and 40 CFR parts 73–78 beginning upon commencement of operation.

(4) *Reporting/Compliance Certification Requirements.* The new unit plan for each unit subject to this section, as provided in paragraph (a) of this section shall require compliance with the compliance certification

requirements specified in subpart K of this part.

(5) Each permit application and compliance plan for a unit subject to this section, as provided in paragraph (a) of this section, shall require compliance with the requirements of paragraph (b) of this section.

(e) *Permitting Authority's Action on Proposed Plan.* The permitting authority shall issue a permit to each unit properly applying for a permit under this section, consistent with the requirements of this part and 40 CFR parts 70, 71 and 73–78.

(f) *Prohibitions.* (1) Beginning on the later of the date a unit subject to this section commences operation on January 1, 2000, or on the date the unit becomes a Phase I affected unit as provided in paragraphs (c) (3) and (4) of this section, it shall be a violation of the Act for the unit to emit an annual tonnage of sulfur dioxide in excess of the number of allowances held, as of the allowance transfer deadline, in the unit's Allowance Tracking System compliance subaccount, or to violate the applicable nitrogen oxides emissions limitation in 40 CFR part 76.

(2) The owners, operators, and designated representative of any unit subject to this section, as provided in paragraph (a) of this section, operated in violation of this section shall be liable for such violation, including liability for failure to fulfill the obligations specified in 40 CFR part 77 and section 411 of the Act. Any such violation shall be a violation of the Act.

§ 72.46 Phase I or phase II nitrogen oxides emissions averaging plans.

(a) Applicability. The provisions of this section shall apply to any affected unit that is a boiler subject to a nitrogen oxides emissions limitation under 40 CFR part 76 during Phase I or Phase II, that seeks to comply with the Acid Rain program nitrogen oxides emissions reductions requirements by emissions averaging with any other such unit.

(b)(1) In lieu of having each unit comply with the applicable emissions limitations under 40 CFR part 76, the designated representative of two or more affected units subject to one or more of the applicable emissions limitations pursuant to 40 CFR part 76 having the same owner or operator, may petition the permitting authority for alternative contemporaneous annual emission limitations for such units; *provided* that such units:

(i) Are affected units for both sulfur dioxide and nitrogen oxides;

(ii) Have the same designated representative, and owner or operator; and

(iii) Are eligible to be combined in an averaging plan pursuant to the criteria for averaging plans specified in 40 CFR part 76 and this section.

(2) The actual annual emissions rate for nitrogen oxides (in lbs/mmBtu) averaged over the units in question, proposed in a plan pursuant to this section, must be less than or equal to the Btu-weighted average annual emissions rate for the same units if they had been operated, during the same period of time, in compliance with the applicable limitations for each such unit provided for in 40 CFR part 76.

(c) Submission Deadline. (1) Proposed nitrogen oxides emissions averaging plans may be submitted at any time and are not limited in duration provided that the other requirements of this section and this part are met.

(2) The designated representative shall submit proposed averaging plans no later than 6 months prior to the end of any calendar year for the plan, if approved, to be deemed to govern operations at the units subject to the plan in that year. Applications received less than 6 months prior to the end of the calendar year shall, if approved, become effective beginning in the following calendar year.

(d) Contents of Proposed Plan. Each proposed nitrogen oxides emissions averaging plan shall be submitted, on the SF# 7246, as provided for in 40 CFR part 76, and shall include the following:

(1) Identification of each unit proposed to be governed by the plan and their common owners or operators;

(2) Certificates of representation, in accordance with subpart B of this part, for the designated representatives for the units proposed to be governed by the plan;

(3) The actual annual total emissions (tons/year) and annual average emissions rate (lbs/mmBtu) from each unit proposed to be governed by the plan for the three preceding years of operation;

(4) A certification that each unit is equipped with an emissions monitoring system certified and operated in accordance with 40 CFR part 75;

(5) The dates during which the averaging plan is proposed to be in effect;

(6) A demonstration, in accordance with this section and 40 CFR part 76, that the actual annual emissions of nitrogen oxides from the units in question, if operated in accordance with the averaging plan, would be less than or equal to the emissions that would occur if the same units had been operated, during the same period of time and under such operating conditions as are specified in the proposed plan, as required by 40 CFR part 76, in compliance with the applicable annual average emissions limitations specified in 40 CFR part 76;

(7) Specification of the operating conditions on which the demonstration in paragraph 6 is based including ranges of fuel type, capacity, operation, and any outages;

(8) A certification that the designated representative shall notify the permitting authority, in accordance with subpart K of this part, within 30 days of any change in the operating conditions specified in paragraphs (d) (6) and (7) of this section and 40 CFR part 76;

(9) The prohibitions specified in paragraph (e) of this section;

(10) If seeking conditional approval of the averaging plan, the expected date by which the Administrator will be notified of an election by the source to activate the option;

(11) The proposed nitrogen oxides emissions rate and utilization limitation in mmBtu that would apply for each unit governed by the plan;

(12) The proposed design or operating conditions that would apply to each unit including the expected range of utilization of each unit, a schedule for achieving any changes in design or operation from those in effect at the time of the demonstration, and an independent assessment, as required by 40 CFR part 76, regarding the emissions effects of such changes;

(13) The applicable test method that will be used to demonstrate compliance with the averaged nitrogen oxides emissions limitation applicable to each unit pursuant to a plan approved in accordance with this section, in accordance with 40 CFR part 76, and the monitoring, recordkeeping, and reporting requirements of 40 CFR part 75;

(14) The recordkeeping requirements specified in 40 CFR part 76 for averaging plans, including records demonstrating compliance with the operating conditions specified in the plan;

(15) Reporting/Compliance Certification Requirements. A requirement that the designated representative submit compliance certifications, in accordance with the requirements in subpart K of this part and 40 CFR part 76.

(e) Permitting Authority's Action on Proposed Plan. (1) Plan Approvals. If the permitting authority determines that the proposed nitrogen oxides emissions averaging plan meets the requirements and conditions of this section and 40 CFR part 76, the permitting authority shall approve the plan in accordance with this part and 40 CFR part 76. The permitting authority may approve the

plan in whole or in part, and with such conditions as appropriate to ensure compliance with the requirements of this part and 40 CFR part 76.

(2) Issuance of Operating Permit. Following approval of an averaging plan, the permitting authority shall issue an operating permit to each source with a unit governed by the plan incorporating such plan in accordance with this part and 40 CFR part 76. If the permitting authority determines that the proposed averaging plan does not meet the requirements of this section, the operating permit(s) issued by the permitting authority in accordance with this part shall require compliance by each unit with the applicable nitrogen oxides emissions limits specified for such unit in 40 CFR part 76.

(3) The emissions limitations in the approved averaging plan shall only remain in effect while all the units that are part of the averaging plan continue operating under the conditions specified, in accordance with this section and 40 CFR part 76, in the approved plan and in each unit's respective operating permit including operation by each unit within the range of utilization (in mmBtu) for the year and fuel type specified in the plan as approved.

(f) Prohibitions. (1) No plan shall be approved under this section unless actual annual emissions of nitrogen oxides authorized by the plan are less than or equal to the actual annual emissions that would have been emitted had each unit operated in compliance with its applicable emissions limitation under 40 CFR part 76.

(2) It shall be a violation of the Act and of the source's permit to operate the units subject to a nitrogen oxides emissions averaging plan approved pursuant to this section so as to exceed the emissions limitations, specified in the approved plan, or so as to fail to fulfill the requirements specified in the approved permit and nitrogen oxides emissions averaging plan.

(3) Failure of the designated representative to notify the permitting authority of operating changes specified in the approved plan pursuant to paragraph (c)(12) of this section, shall be a violation of the Act.

(4) The owners, operators, and designated representative of the units governed by an approved nitrogen oxides emissions averaging plan shall be liable for any violation by any such unit or any other unit governed by the plan or this section, part 76, or the plan, including liability for a failure to fulfill the obligations specified in 40 CFR part 77 and section 411 of the Act. Any such violation shall be a violation of the Act.

§ 72.47 Phase I or phase II nitrogen oxides alternative emissions limitations plans.

(a) Applicability. The provisions of this section shall apply to any affected unit that is a boiler subject to a nitrogen oxides emissions limitation under 40 CFR part 76 during Phase I or Phase II, for which an alternative emissions limitation for nitrogen oxides is sought.

(b) The designated representative of an affected unit subject to a nitrogen oxides emissions limitations under 40 CFR part 76 may petition the permitting authority for an emissions limitation less stringent than the applicable limitation established under 40 CFR part 76, *provided* That the designated representative demonstrates to the satisfaction of the permitting authority in accordance with this section and 40 CFR part 76 that:

(1)(i) In the case of a tangentially-fired boiler or a dry bottom wall-fired boiler (other than a unit applying cell burner technology), it cannot meet the applicable limitation specified in 40 CFR part 76 for such boiler category using low nitrogen oxides burner technology as defined in 40 CFR part 76; or

(ii) In the case of a wet bottom wall-fired boiler, a cyclone, a unit applying cell burner technology or any other type of utility boiler, it cannot meet the applicable limitation specified in 40 CFR part 76 for such boiler category using the technologies specified in 40 CFR part 76 upon which the Administrator based such applicable emissions limitation; and

(2) The owners or operators:

(i) Have properly installed control equipment designed to meet the applicable emissions limitation, and have operated such equipment in accordance with vendor specifications and procedures for at least 6 months before submitting the application; or

(ii) Make a demonstration, in accordance with procedures specified in this section and 40 CFR part 76, that because the unit cannot meet the requirements of paragraph (b)(2)(i) of this section technology upon which the limitation was based cannot be designed for that unit so as to comply with the limitation.

(3) Units with tangentially-fired or dry bottom wall-fired boilers (other than units applying cell-burner technology) for which an alternative emissions limitation is established shall not be required to install any additional control technology beyond low nitrogen oxides burner technology.

(4) Nothing in this section shall preclude a designated representative from installing and operating an alternative nitrogen oxides control technology capable of achieving the applicable emissions limitation.

(c) Deadlines for submission of proposed compliance plan. (1) Applications for nitrogen oxides alternative emissions limitations shall be filed in two stages as follows:

(i) An application for a 15-month demonstration period, using SF# 7247 in appendix C of this part, as specified in paragraph (d)(1) and in 40 CFR part 76 may be filed at any time subject to paragraph (c)(2) of this section; and

(ii) An application for a final alternative emissions limitation, using SF# 7247A in appendix C of this part, as specified in paragraph (d)(2) of this section and in 40 CFR part 76, shall be filed not later than 6 months before the conclusion of the demonstration period approved by the permitting authority in accordance with paragraph (e)(1) of this section and 40 CFR part 76.

(2) The designated representative shall submit the application for a demonstration period for a proposed nitrogen oxides alternative emissions limitation to the permitting authority at least 3 months before the end of the calendar year in order for the alternative demonstration period emissions limitation, if approved, to govern operations during that year.

(d) Contents of proposed plan. (1) Demonstration period plan. The application for approval of a demonstration period shall be submitted on a Nitrogen Oxides Alternative Emissions Limitation Demonstration Period Plan SF# 7247 in appendix C of this part, and shall include the following information:

(i) The unit name and identification number.

(ii) A certification by an independent auditor, in accordance with the requirements set forth in 40 CFR part 76, that the conditions specified in paragraph (b) of this section apply to the unit, including:

(A) That the appropriate control equipment designed to meet the applicable emissions limitation at the unit was properly installed, and has been properly operated for a period of no less than 6 months, including a vendor certification that there is no adjustment to the equipment that can be done such that the unit would be able to achieve the applicable limit of 40 CFR part 76; or

(B) In lieu of the requirements in paragraph (d)(1)(ii)(A) of this section, (*1*) a list of all vendors of equipment (name address, phone number) designed for the unit's boiler type, (*2*) identification of which vendors, of those listed pursuant to the preceding subparagraph, were

contacted by the source, and the date each vendor was contacted for purpose of supplying such equipment, (*3*) copies of any solicitations for bids, purchase orders, or nitrogen oxides control equipment design, engineering, and construction contracts, and (*4*) the certification of the vendors contacted that technology cannot be designed for that unit which will meet the applicable limitation of 40 CFR part 76;

(iii) Operating information and monitoring data, collected by an emissions monitoring system certified in accordance with the requirements of 40 CFR part 75 (emissions monitoring regulations), for the same period identified in paragraph (d)(1)(ii)(A) that demonstrates in accordance with this section and 40 CFR part 76 that the unit cannot meet the applicable limitation of 40 CFR part 76;

(iv) A proposed interim alternative emissions limitation that the unit shall meet on an annual average basis during the demonstration period, calculated in accordance with 40 CFR part 76;

(v) The operating and recordkeeping requirements that would apply to the unit during the demonstration period, in accordance with 40 CFR part 76, including the design engineering and operating protocol;

(vi) A statement that the demonstration plan, if approved, will be conditional on the subsequent timely submission by the designated representative of periodic compliance certifications submitted in accordance with subpart K and 40 CFR part 76 to document and certify the operations and emissions at the unit during the demonstration period.

(vii) The prohibitions of paragraph (f) of this section.

(2) Alternative emissions limitation plan. Not later than 6 months before the final date of the demonstration period specified in the demonstration plan submitted under paragraph (d)(1) of this section, as approved pursuant to paragraph (e) of this section, the designated representative of each unit governed by the approved demonstration plan shall submit a proposed Nitrogen Oxides Alternative Emissions Limitation Plan, using SF# 7247A in appendix C of this part, which shall include the following information:

(i) Identification of the unit name and identification number.

(ii) Certification, in accordance with the requirements of 40 CFR part 76 and the permit for that unit, that the unit was operated in accordance with the demonstration plan during the demonstration period (excluding the final 6 months);

(iii) Operating and monitoring data collected to date for the demonstration period, in accordance with the requirements of 40 CFR parts 75 and 76, establishing that the unit cannot meet the applicable limit of 40 CFR part 76 using applicable technology;

(iv) Certification that the data required to be collected for the balance of the demonstration period shall be submitted to the permitting authority in accordance with the requirements of 40 CFR part 76, but not later than 30 days following the end of the demonstration period;

(v) An emissions limitation that the unit can meet, calculated according to 40 CFR part 76;

(vi) The design, equipment work practice and operational standards that will apply to the unit, in accordance with 40 CFR part 76;

(vii) The test method, recordkeeping and compliance certification requirements that will apply to the unit in accordance with this part and 40 CFR part 75 and part 76; and

(viii) The prohibitions of paragraph (f) of this section.

(e) Permitting authority's action on proposed plans. (1) Demonstration period plan. If the permitting authority determines that the nitrogen oxides alternative emissions limitation demonstration period plan meets the requirements of paragraphs (a) through (d)(1) of this section and 40 CFR part 76, the permitting authority shall approve the plan and shall issue an operating permit, or a revision to the operating permit under § 72.302 (fast-track permit modifications) for the source in question, in accordance with this part and 40 CFR part 76, incorporating the plan as approved, and authorizing the unit governed by the plan to be operated during the demonstration period pursuant to the interim emissions limitation and operating conditions specified in the approved plan. The demonstration period shall include retrospectively the 6 month operating period prior to application proposed demonstration plan during which the unit operated in a manner consistent with the plan as approved, provided that the demonstration period shall total not less than 15 months.

(2) Final alternative emissions limitation plan. (i) If the permitting authority determines that the final nitrogen oxides alternative emissions limitation plan meets the requirements of paragraphs (a) through (d)(2) of this section, the Administrator shall approve the plan. If the final limit is more stringent than the demonstration period limit the permitting authority may include as part of the plan as approved a schedule for the unit to achieve compliance with the limit as expeditiously as practicable. Thereafter, the permitting authority shall issue an operating permit, or revise the operating permit for the source in accordance with § 72.301 (permit modification) for the source in question, in accordance with this part and 40 CFR part 76, incorporating the plan as approved and authorizing the unit governed by the plan to be operated during the remainder of the permit term pursuant to the emissions limitation and operating conditions specified in the approved plan.

(ii) Each permit renewal application for a source with a unit governed by a plan approved under this section shall include a demonstration, in accordance with 40 CFR part 76, justifying the continued applicability of an alternative limit to the unit. If the alternative limit proposed as part of a renewal application is more stringent than the previously approved alternative limit, and shows progress by the unit toward meeting the applicable limit of 40 CFR part 76, such limit shall be deemed automatically approved.

(f) Prohibitions. (1) It shall be a violation of the Act for any unit subject to an alternative emissions limitation to emit in excess of the applicable limit established in accordance with this section and 40 CFR part 76.

(2) The owner or operator and the designated representative of any unit operated in violation of this section and 40 CFR part 76 shall be fully liable for such violation, including liability for fulfilling the obligations specified in 40 CFR part 77 and section 411 of the Act.

(3) It shall be a violation of the Act for a unit with an approved nitrogen oxides alternative limitation plan to emit nitrogen oxides during the demonstration period in excess of the limitation assigned pursuant to 40 CFR part 76.

(4) At the conclusion of the demonstration period, it shall be a violation of the Act for a unit with an approved nitrogen oxides alternative limitation plan to emit nitrogen oxides in excess of the final emissions limitation approved by the permitting authority pursuant to this section and 40 CFR part 76.

§ 72.48 Phase I nitrogen oxides compliance deadline extension plans.

(a) Applicability. The provisions of this section shall apply to any affected unit that is a boiler subject to the nitrogen oxides emissions limitation under 40 CFR part 76 during Phase I and that seeks an extension of the Phase I

nitrogen oxides emissions reductions compliance deadline (January 1, 1995).

(b) The designated representative of a unit in paragraph (a) of this section may apply for an extension of the Phase I nitrogen oxides deadline for compliance of 15 months by demonstrating to the satisfaction of the Administrator that the technology necessary to meet such requirements is not in adequate supply to enable its installation and operation at the unit, consistent with system reliability, by January 1, 1995.

(c) Special Procedures. (1) Requests for extension of the Phase I nitrogen oxides deadline must be submitted no later than December 31, 1994.

(2) Any demonstrations claiming maintenance of system reliability as a factor in the need for an extension shall be deemed valid only if such equipment and timing problems are due solely to nitrogen oxides control equipment availability and installation.

(d) Contents of proposed plan. (1) Demonstration requirements. Each proposed plan shall include a demonstration in accordance with this section and 40 CFR part 76. Such demonstration may include a showing that equipment supply is inadequate to enable its installation and operation at the unit, consistent with system reliability, in time for compliance by the unit with the Phase I emissions reduction requirements by 1995. Each demonstration shall include the information required by 40 CFR part 76, using SF# 7248 in appendix C of this part, and may include:

(i) A list of all vendors of equipment (name, address, phone number) capable of meeting the applicable emissions limitation;

(ii) Information about the vendors identified in the list required by paragraph (d)(1)(i) of this section that were contacted by the source, including information specifying the date the vendor was contacted for the purpose of supplying such equipment, copies of any solicitations for bids, purchase orders or design, engineering and construction contracts, and other documentation of the source's efforts to purchase and install the equipment in a timely manner;

(iii) Certifications, as required by 40 CFR part 76, by the vendors contacted that they cannot provide and install the appropriate equipment in time for the unit to comply with the applicable emissions limitation by 1995, including the reasons why the equipment cannot be supplied or installed in a timely manner.

(2) Compliance requirements. (i) Technology standards. Each proposed compliance plan submitted under this section shall include:

(A) A design, engineering, and construction contract;

(B) A vendor warranty that the installed technology will meet the emissions limitation applicable to the unit under 40 CFR part 76;

(C) A vendor construction and installation schedule, including dates specifying:

(*1*) Commencement of construction;

(*2*) Completion of construction;

(*3*) Start-up testing of the technology; and

(*4*) Commencement of operation.

(D) Such other information as required in 40 CFR part 76, including the applicable test method for demonstrating compliance and all recordkeeping and compliance certification requirements that will apply under the plan.

(ii) Emissions limitations and operational standards. Each proposed compliance plan submitted under this section shall specify, in accordance with 40 CFR part 76:

(A) Extension period requirements, as specified in 40 CFR part 76;

(B) The final emissions limitation and compliance deadline that will apply.

(C) The test method for determining compliance with the nitrogen oxides emissions limitations applicable to a unit pursuant to a plan approved in accordance with this section, determined in accordance with 40 CFR part 76 and the monitoring recordkeeping and reporting requirements of 40 CFR part 75.

(iii) Design, equipment, work practice or operational standards as specified in 40 CFR part 76.

(3) Recordkeeping requirements. Each proposed compliance plan submitted under this section shall specify requirements for maintaining records at the source, in accordance with 40 CFR part 76.

(4) Reporting/compliance certification requirements. Each proposed compliance plan submitted under this section shall specify compliance certification requirements, in accordance with subpart K of this part and 40 CFR part 76, including notices concerning the achievement of any scheduled increments of progress.

(e) Administrator's action on proposed plan. (1) The Administrator shall act on each proposed extension plan within 3 months of receipt as provided in 40 CFR part 76.

(2) The Administrator may deny the proposal, or approve the proposed extension plan in whole or in part with such conditions as may be appropriate to ensure expeditious compliance with the Phase I emissions limitations applicable to the unit under 40 CFR part 76. The Administrator shall grant an extension that terminates upon commencement of operation of the nitrogen oxides control equipment, but not longer than 15 months.

(f) Prohibitions. The owner or operator and the designated representative of any unit governed by a compliance plan approved by the Administrator in accordance with this section and 40 CFR part 75 and part 76 shall be liable for such violation, including liability for a failure to fulfill the obligations specified in 40 CFR part 77 and section 411 of the Act. Any such violation shall be a violation of the Act.

§ 72.49 Phase I or phase II opt-in plans.

(a) This section shall apply to sources eligible to opt-in to the Acid Rain program, as provided in 40 CFR part 74.

(b) For any source electing to opt-in to the Acid Rain program, the designated representative shall submit a permit application and proposed compliance plan in accordance with 40 CFR part 74.

(c) Any opt-in source shall be an affected source for sulfur dioxide under the Acid Rain program subject to all the requirements of the program as provided in 40 CFR part 74.

(d) Prohibitions. The owner or operator and the designated representative of any unit governed by a compliance plan approved by the Administrator in accordance with this section and 40 CFR part 74 and part 75 shall be liable for such violation, including liability for a failure to fulfill the obligations specified in 40 CFR part 77 and section 411 of the Act. Any such violation shall be a violation of the Act.

§ 72.50 Phase I or phase II common-stack plans.

(a) Applicability. The requirements of this section shall apply to any affected source with two or more units utilizing a common stack where the emissions from each unit are not separately monitored by an emissions monitoring system certified and operating in accordance with 40 CFR part 75, including any common stack situation involving two or more affected units, any common stack situation during Phase I involving one affected unit and other units not otherwise affected during Phase I, and any common stack situation involving an affected unit and an unaffected unit utilizing a common stack.

(b)(1) Where two affected units utilize a common stack and the emissions from such units are not separately monitored by emissions monitoring systems certified and operating in accordance

with 40 CFR part 75, the designated representative shall so state in the permit application.

(2) During Phase I:

(i) Where an appendix A unit and an appendix B unit utilize a common stack and the emissions from such units are not separately monitored by emissions monitoring systems certified and operating in accordance with 40 CFR part 75, the designated representative shall identify the common-stack in the proposed monitoring plan for the source, using SF# 7512 in part 75 and shall designate the appendix B unit as a substitution unit and submit a substitution plan pursuant to § 72.41, on SF# 7241 in appendix C of this part, with the permit application for the source. Such substitution plan shall be subject to § 72.42(b)(4) exempting it from the requirement to reassign emissions reductions.

(ii) Where an appendix A or a Phase I affected appendix B unit and an otherwise unaffected unit subject to § 72.45(a) (e.g. new unit) share a common stack, and the emissions from such units, are not separately monitored by emissions monitoring systems certified and operating in accordance with 40 CFR part 75, the designated representative of the unaffected § 72.45(a) unit shall submit a Phase I permit application and monitoring plan not later than the later of February 15, 1993 or 24 months before the unit commences operation. Such § 72.45(a) unit shall be subject to the Phase I requirements of this part and parts 73–78, including the requirement to hold allowances equal to or greater than its annual sulfur dioxide emissions beginning on the later of January 1, 1995 or commencement of operation. Such unit shall receive no allowances and shall have a baseline of zero.

(3) Where an affected unit and a non-affected unit utilize a common stack and the emissions from such units are not separately monitored by emissions monitoring systems certified and operating in accordance with 40 CFR part 75, the designated representative shall identify the common-stack in the proposed monitoring plan for the source using SF# 7512 in appendix C of this part and shall designate the nonaffected unit as an opt-in unit and submit an opt-in plan in accordance with 40 CFR part 74 and § 72.49 on the form specified in 40 CFR part 74.

(4) Where two or more units share a common stack, and where not all of the units are otherwise subject to Acid Rain nitrogen oxides requirements, the units shall either separately monitor their nitrogen oxides emissions or otherwise differentiate their emissions, in accordance with the monitoring requirements of 40 CFR part 75, or all emissions from the units shall be subject to the most stringent Acid Rain nitrogen oxides emissions limitation applicable to any one of the units sharing the common stack. For two or more units that are subject to Acid Rain nitrogen oxides requirements that cannot be separately monitored or where the emissions cannot otherwise be differentiated pursuant to 40 CFR part 75, the unit shall either average their emissions pursuant to 40 CFR part 76, or they shall be subject to the most stringent limit.

(c) All units governed by a common-stack plan shall have one designated representative.

(d) No permit shall be issued to a source with units sharing a commonstack unless the requirements of this section are met. Notwithstanding any other provisions of this part, no common- stack plan may be submitted as a conditional compliance option.

(e) The requirements of paragraphs (b)-(d) of this section shall not apply where each unit is equipped with a fully certified continuous emissions monitoring system to differentiate the emissions from the respective units.

(f) Prohibitions. The owner or operator and the designated representative of any unit governed by a compliance plan approved by the Administrator in accordance with this section and 40 CFR part 75 and part 76 shall be liable for such violation, including liability for a failure to fulfill the obligations specified in 40 CFR part 77 and section 411 of the Act. Any such violation shall be a violation of the Act.

Subpart E—Acid Rain Permit Contents

§ 72.51 General.

Each Acid Rain permit issued to an affected source under this part and 40 CFR parts 70 and 71 shall contain the information required by this section, as follows:

(a) Standard permit information about the source, using SF# 7251 in appendix C of this part;

(b) For Phase I permits, the NERC region or subregion where the source is located, and the name of the utility system for the source.

(c) The most stringent federally enforceable emissions limitation for sulfur dioxide and nitrogen oxides for each unit at the source.

(d) The initial sulfur dioxide allowance allocation for each unit at the source, under 40 CFR part 73; the nitrogen oxides emissions limitation applicable to each unit at the source, if any; and the standard provisions in § 72.54 of this part.

(e) The compliance deadline for each emissions limitation.

(f) An approved compliance plan for each unit at the source including:

(1) The Acid Rain compliance option(s), using the standard forms specified in subpart C of this part, approved for each unit at the source, and the terms and conditions of that approval; and

(2) The monitoring plan approved by the Administrator, pursuant to 40 CFR part 75, for each unit at the source, and certifications for each monitor at the source in accordance with 40 CFR part 75; *Provided*, That

(i) In the event that a monitor for the unit has not been certified, the permit shall include enforceable deadlines by which the unit shall submit monitor verification data, in accordance with 40 CFR part 75;

(ii) Thereafter the monitor certification issued by the Administrator shall be incorporated into the permit as an administrative amendment pursuant to the permit revision procedures in § 72.303.

(g) The certificate of representation for the source's designated representative and for each other designated representative required to sign a multi-source compliance plan.

(h) Each Acid Rain permit issued pursuant to this part or 40 CFR part 70 or part 71, shall require that each affected unit governed by the permit must comply with the emissions monitoring requirements of this part and 40 CFR part 75, of the monitoring plan approved by the Administrator, and of any alternative monitoring system as required by paragraph (i) of this section. Except as provided in paragraph (i) of this section, these requirements shall include the installation, operation, quality assurance, and certification of continuous emissions monitoring systems and the reporting of continuous emissions monitoring system data.

(i) Alternative monitoring systems. (1) Data from an alternative monitoring system shall be authorized by the permit in lieu of continuous emissions monitoring system data only if collected pursuant to an alternative monitoring method approved by the Administrator pursuant to 40 CFR part 75, and incorporated into the permit pursuant to paragraph (f)(2)(ii) of this section. Such approval shall specify the required installation schedule and operating conditions of the alternative monitoring system, appropriate quality assurance methods, frequency and parameters for testing, and the method that shall apply

to calculate emissions when data from the system is unavailable. The approval documentation requirements shall be expressly incorporated into the permit for the unit. Failure to operate the alternative monitoring system in accordance with the conditions of the Administrator's approval of the method shall be deemed a violation of the permit.

(2) Any approval by the Administrator of an alternative monitoring system shall be incorporated into the permit without modification or revision by the permitting authority as an administrative amendment pursuant to § 72.303.

(j) Each Acid Rain permit issued pursuant to this part, 40 CFR part 70 or 71 shall provide that:

(1) The affected source governed by the permit shall retain records of:

(i) All monitoring information, including all calibration and maintenance records;

(ii) Copies of all reports required by this part;

(iii) The raw emissions and operational data used to generate the reports; and

(iv) Records of all information used to complete the permit application.

(2) All such records shall be retained pursuant to § 72.10.

(3) All applications, reports, or information submitted to the permitting authority shall be signed and certified pursuant to § 72.9 and subpart K of this part. Each Acid Rain permit shall incorporate the definitions contained in the Act, as supplemented by this part, and 40 CFR parts 73–78, by reference without modification.

(4) It shall be a violation of the permit and of the Act for a source to fail to comply with any permit provision including the requirement to submit the emissions monitor verification data, or to obtain certification of a monitor, as required by paragraph (f)(2) of this section and 40 CFR part 75, in a timely manner.

§ 72.52 Compliance plan.

(a) The compliance plan and all of its terms, requirements, and conditions, as approved or revised by the permitting authority in accordance with this part, shall accompany, be incorporated into and deemed a part of any Acid Rain permit issued pursuant to this part or 40 CFR part 70 or 71.

(b)(1) Each permit shall require that the affected unit hold allowances in its Allowance Tracking System compliance subaccount as of the compliance transfer deadline, as provided in 40 CFR part 73, equal to or greater than the unit's emissions for the year.

(2) Each compliance option proposed for conditional approval in a plan submitted pursuant to subpart D of this part, and approved by the permitting authority, shall be incorporated into the permit by reference whether or not such compliance option is activated.

(i) The designated representative for a unit may activate a conditionally approved compliance option which is incorporated into a permit by notice pursuant to § 72.303 (administrative permit amendment).

(ii) The designated representative for a unit may terminate a compliance option pursuant to § 72.303 (administrative permit amendment), subject to the limitations on terminating substitution plans specified in § 72.41, Phase I Extension plans specified in § 72.42, reduced utilization compensating unit plans specified in § 72.43, and repowering extension plans specified in § 72.44.

(iii) Where a multi-unit plan involves more than one source, the designated representative for each source governed by the plan must sign and certify an administrative amendment terminating such plan.

§ 72.53 Permit application shield and permit shield.

(a) *Permit application shield.* Once a designated representative submits a timely and complete permit application for an affected source to the permitting authority in accordance with this part (including a proposed compliance plan for each affected unit at the source), and until such time as the permitting authority makes a final permitting decision on the application, the affected unit shall be deemed to be in compliance with the requirement to have a permit set forth at 40 CFR part 70; *Provided* That any delay by the permitting authority in making a final permitting decision is not caused by a failure of the designated representative, owners, or operators of the source to submit, in a complete or timely fashion, supplemental information as required by the permitting authority pursuant to this part or 40 CFR parts 73–78, necessary to make such final permitting decision.

(b) *Permit Shield.* (1) Each affected unit at an affected source that is operated in accordance with the terms and requirements of an Acid Rain permit issued in compliance with the requirements of title IV of the Act, as provided in this part and 40 CFR parts 73–78, shall be deemed to be operating in compliance with the Acid Rain program and title IV of the Act. (See 40 CFR 70.6(h)(1).)

(2) Pursuant to section 408 of the Act, prior to the date a permitting decision is issued each affected source operated in compliance with the terms and requirements of a complete Acid Rain permit application and proposed compliance plan (including compliance with any conditions imposed by the Administrator when issuing the determination of completeness) that complies with the requirements of this part and 40 CFR parts 73–78 shall be deemed to be operating in compliance with the terms and requirements of the Acid Rain program and title IV of the Act, unless and until such permit application and proposed compliance plan are disapproved by the permitting authority. The terms and conditions of an Acid Rain permit issued for an affected source under this part shall supersede the Acid Rain permit application and proposed compliance plan for the unit on the permit's issuance date.

§ 72.54 Prohibitions and standard conditions.

(a) *General.*—Each Acid Rain program permit and permit application shall specify the duties, prohibitions and provisions and duties, prohibitions and such provisions shall apply to and be binding on the affected source named in the permit or permit application, all affected units at the source, all other units governed by the terms of the compliance plan submitted with the permit application, and all owners, operators and designated representatives of all source(s) and unit(s) named in the permit application or governed by the permit and any applicable compliance plan (including any new owners and operators as provided in § 72.24 and § 72.200(h)).

(b) *Duties, Prohibitions and Liability.*—(1) *Duties.* Each owner, operator, and designated representative of an affected unit shall have the following affirmative duties in connection with the Acid Rain program. Failure to fulfill or comply with these duties shall be a violation of the Act and of 40 CFR part 72. The duties are as follows:

(i) To submit a permit application and proposed compliance plan under 40 CFR part 72 in accordance with the deadlines specified in § 72.30;

(ii) To submit in a timely manner any additional information that the permitting authority requires for the complete review of a permit application.

(iii) To operate any affected unit in compliance with the terms, conditions, requirements, and prohibitions of an Acid Rain permit application and proposed compliance plan properly submitted in accordance with title IV of

the Act and of 40 CFR part 72 (including any amendments or modifications thereto required by the permitting authority), or of the superseding Acid Rain permit issued by the permitting authority.

(iv) To operate the unit in compliance with the monitoring requirements of 40 CFR part 75.

(v) In the case of an affected unit with excess emissions in any calendar year, to pay without demand the penalty required pursuant to 40 CFR part 77; and

(vi) In the case of an affected unit with excess emissions in any calendar year, to comply with the offset planning requirements of 40 CFR part 77 and an approved offset plan as required by 40 CFR part 77.

(2) *Prohibitions.* Any violation of the following prohibitions shall be a violation of the Act and 40 CFR part 72 by the owners, operators and designated representative of the affected unit and/or affected source:

(i) No affected unit shall exceed the applicable emissions limitations of 40 CFR parts 72–78, as follows:

(A) No affected unit shall emit sulfur dioxide in any calendar year in excess of the allowances held in the unit's Allowance Tracking System compliance subaccount as of the allowance transfer deadline for use in the calendar year as provided in 40 CFR part 73. Each ton of sulfur dioxide emitted in excess of the allowances held shall constitute a separate violation of the Act.

(B) No affected unit shall emit nitrogen oxides in excess of

(*1*) The annual emissions limitation for the unit by the type of boiler, as specified in 40 CFR part 76; or

(*2*) The superseding limitation specified in an approved nitrogen oxides compliance option incorporated into the Acid Rain permit issued by the permitting authority in accordance with 40 CFR part 72, subpart D and 40 CFR part 75;

(ii) No person shall hold, use, or transfer any allowance except in accordance with title IV of the Act and the regulations in 40 CFR parts 72–78.

(iii) No person shall use an allowance prior to the calendar year for which the allowance was allocated.

(iv) No person shall make a false statement in any submission required under 40 CFR parts 72–78, inclusive.

(3) *Liability.* (i) Any person who knowingly violates any requirement or prohibition of title IV of the Act, of 40 CFR parts 72–78, of an Acid Rain permit application filed pursuant to the requirements of title IV of the Act and 40 CFR parts 72–78, or of an Acid Rain permit, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.

(ii) The owners, operators, and designated representative of any affected unit governed by a multi-unit compliance plan that is filed or approved by the Administrator or permitting authority pursuant to the requirements of title IV of the Act and 40 CFR parts 72–78 shall be liable for any violation of the plan at that or any other unit governed by the compliance plan, including liability for failure to fulfill the obligations specified in 40 CFR part 77 and section 411 of the Act. Any such violation shall be a violation of the Act.

(iii) Any person who knowingly makes false material statement in any record, submission, or report required by the Acid Rain program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.

(iv) No permit revision shall excuse past noncompliance.

(c) *Standard provisions*—(1) *Continuous emissions monitoring requirements.* (i) The owners, operators and designated representative of the units at this source shall comply with all the emissions monitoring requirements of 40 CFR part 75, including:

(A) The duty to collect and report emissions data for each unit at the source and to adopt quality assurance procedures and conduct quality assurance reviews of the emissions monitoring system and the data for sulfur dioxide, nitrogen oxides, opacity and volumetric flow at each unit at the source as specified in 40 CFR part 75; and

(B) The duty to calculate emissions pursuant to the missing data provisions of 40 CFR part 75 if emissions monitoring data are not available for any affected unit during any period when such data are required;

(ii) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other provisions of the operating permit for the source.

(iii) No affected unit or source shall use alternative monitoring system data or procedures unless the Administrator approves the alternative monitoring system in accordance with 40 CFR part 75, and the unit operates the system in accordance with that approval.

(2) *Recordkeeping and reporting requirements.* (i) The owners, operators, and designated representative of the affected units at the affected source shall keep the following records for a period of 5 years on site at the affected source governed by the permit or permit application.

(A) The certificate of representation for the designated representative for the source and each unit at the source, and all documents that support the certificate, as provided in 40 CFR part 72, subpart B.

(B) All emissions monitoring information, including but not limited to calibration and maintenance records, quality assurance procedures information, and raw emissions and operation data used to generate emissions reports that a source or unit must collect under the requirements of 40 CFR part 75;

(C) Copies of all reports required by 40 CFR parts 72–78; and

(D) Copies of all documents, contracts, agreements, guarantees, schedules, operating procedures, allowance documentation, or any other records of information used to complete the permit application and compliance plan or to demonstrate compliance with the requirements of the Acid Rain program.

(ii) The designated representative shall submit quarterly and annual compliance certifications as required by 40 CFR part 72 subpart K and other provisions of 40 CFR parts 72–78.

(3) *Allowance information.* (i) An allowance allocated by the Administrator under the Acid Rain program is a limited authorization to emit sulfur dioxide in accordance with the provisions of title IV of the Act and 40 CFR parts 72–78. Nothing in title IV, in 40 CFR parts 72–78, in this permit application, or in any provision of law shall be construed to limit the authority of the United States to terminate or limit the authorization.

(ii) An allowance allocated by the Administrator under the Acid Rain program does not constitute a property right.

(4) *Effect on other authorities.* (i) Nothing in title IV, in 40 CFR parts 70–78, or in this permit (application) shall be construed as limiting the number of allowances a unit can hold; *Provided,*That the number of allowances held by a unit shall not affect the applicability of, or the affected source's obligation to comply with, any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans.

(ii) Nothing in title IV, in 40 CFR parts 70–78, or in this permit (application) shall be construed as requiring a change of any kind in any State law regulating

electric utility rates and charges, or as affecting any State law regarding such State regulation, or as limiting such State regulation, including any prudence review requirements under such a State law.

(iii) Nothing in title IV, in 40 CFR parts 70–78, or in this permit (application) shall be construed as modifying the Federal Power Act or as affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act.

(iv) Nothing in title IV, in 40 CFR parts 70–78, or in this permit (application) shall be construed to interfere with or impair any program for competitive bidding for power supply in a State in which such program is established.

(5) *Definitions.* This permit (application) adopts by reference all definitions found at 40 CFR part 72.

Subpart F—Acid Rain Phase I Implementation

§ 72.60 Deadlines for submitting phase I permit applications.

(a) *Applications and compliance plans.* For every Phase I affected source, the designated representative shall submit a complete Acid Rain permit application including a proposed compliance plan specifying compliance options for each affected unit at the source, in accordance with this part, on or before February 15, 1993. The Acid Rain permit application and proposed compliance plan shall be binding on the designated representative pursuant to § 72.33: *Provided* that the application and proposed compliance plan are consistent with this part.

(b) *Continuous emissions monitoring systems.* Notwithstanding § 72.60(a) and any permit application deadlines, the designated representative of each Phase I affected unit, for which the Administrator had not certified a continuous emissions monitoring system or approved an alternative monitoring system at the time the permit application was submitted, shall, in accordance with 40 CFR part 75, not later than November 15, 1993 demonstrate to the Administrator that a continuous emissions monitoring system has been installed and is being operated to monitor the emissions from each Phase I affected unit at the source, including any substitution, compensating, or opt-in unit, that all data is being quality assured, that records and reports are being kept, and that the system is eligible for certification in accordance with 40 CFR part 75.

§ 72.61 Administrator's action on phase I permit applications and compliance plans.

(a) *Administrator's action on Phase I applications and compliance plans.* (1) The Administrator shall review and issue a permitting decision, in accordance with the procedures set forth in subpart G of this part, on each complete Acid Rain Phase I permit application and proposed compliance plan submitted by a designated representative for a source under this paragraph, determining whether the submission satisfies the requirements of title IV of the Act, of this part, and of 40 CFR parts 73–78 within 6 months of receipt of the complete submission at the appropriate U.S. EPA Regional office; *Provided* That the Administrator shall not review any Acid Rain program submission for an affected source or unit unless made by a designated representative who has been duly certified for the source or unit, as provided in subpart B; *Provided further,* That the Administrator shall not be required to issue a permitting decision within 6 months where the applicant has failed to submit a complete application.

(2) Acid Rain permit applications and compliance plans that meet the requirements of title IV, of this part, and of 40 CFR parts 73–78, shall be approved, in whole or in part, and with such modifications or conditions as may be appropriate. All other applications and proposed compliance plans shall be denied, subject to paragraphs (c) through (e) of this section. A notice of denial shall be sent to the source stating the reasons of the denial, and shall be a permitting decision under this part.

(b) *Approved applications and compliance plans.* (1) The Administrator shall issue a proposed Phase I Acid Rain permit for each affected source for which an Acid Rain permit application and compliance plan have been approved or modified as provided in paragraph (a) or (c) of this section. Issuance or denial of the permit shall constitute a permitting decision for purposes of any appeals under subpart H.

(2) Each Phase I Acid Rain permit issued by the Administrator shall become effective January 1, 1995, and shall have a term of 5 years commencing on its effective date.

(3) Prior to the effective date of the Phase I permit issued by the Administrator, the approved Phase I Acid Rain permit application and compliance plan shall be binding on the designated representative, owners, and operators of the affected source for purposes of this part and 40 CFR parts 73–78; and shall be enforceable in lieu of the permit until the effective date of the permit. Thereafter, the affected source and its designated representative, owners, and operators, shall be bound by the terms of the permit.

(c) *Denial of Acid Rain permit applications and proposed compliance plans.* (1) Prior to denying an Acid Rain permit application or proposed compliance plan under paragraph (a)(2) of this section, the Administrator shall notify the designated representative of the possible denial, the reasons for the denial, and any changes that are needed for the application and proposed compliance plan to be approved.

(2) The Administrator shall prescribe an appropriate date by which the required changes must be made by the designated representative, not to exceed 60 days.

(i) The Administrator may grant a 30-day extension of this deadline for good cause shown. Failure by the designated representative to make the required changes to the application and proposed plan by the date specified in the notice of denial, or in any extension granted, shall be grounds for automatic denial of the permit.

(ii) In no event shall any such extension excuse a failure of the affected source to submit a complete Phase I permit application and proposed compliance plan meeting the requirements of this part by February 15, 1993, or to comply with any requirements of 40 CFR parts 73–78.

(3) Effect of denials. (i) Denied applications and compliance plans shall not be binding on the source.

(ii) Denied applications and compliance plans shall not shield the source from underlying requirements of the Act, pursuant to § 72.53.

(4) A notice of denial under paragraph (a)(2) of this section shall be deemed to satisfy the deadline for the Administrator to act on complete permit applications under paragraph (a)(1) of this section.

(d) *Permit application correction.* (1) The Administrator shall approve or deny any proposed correction to a permit application or proposed compliance plan submitted pursuant to paragraph (c) of this section, within 6 months of receipt.

(2) Upon denial of a proposed correction to an Acid Rain permit application or proposed compliance plan, the Administrator shall notify the designated representative of the reasons for the denial. Such denial shall not be subject to review pursuant to subpart H, until a permitting decision has been issued pursuant to this section.

(e) *Failure to submit an approvable Phase I permit application and proposed*

compliance plan. It shall be a violation of this part and of the Act for a designated representative to fail to submit a Phase I permit application and compliance plan meeting the requirements of this part by February 15, 1993. The Administrator shall issue a permitting decision denying a permit to any source failing to submit an approvable Phase I permit application and proposed compliance plan. Such denial shall constitute a permitting decision for purposes of subpart H. The owners, operators, and designated representative for the affected source shall be thereafter liable for operating the affected unit without a permit, as provided in § 72.53(a), until such time as a complete permit application and proposed compliance plan meeting the requirements of the part are submitted to the Administrator.

Subpart G—Federal Acid Rain Permit Issuance Procedures

§ 72.70 General.

(a) *Scope.* This subpart contains the procedures for Federal issuance of Acid Rain permits for Phase I of the Acid Rain program, and for Phase II for sources located in States where the Administrator is the permitting authority as provided under 40 CFR part 71. Except as expressly provided in this part, the procedures in this subpart do not apply to Acid Rain permitting by State or local permitting authorities with programs approved under 40 CFR part 70. The Acid Rain permit program requirements that must be adopted by States and localities in order to gain approval for an operating permit program under 40 CFR part 70 are set forth in subpart I of this part.

(b) *Permit decision deadlines.* (1) The permit decision deadlines set forth in subpart F shall apply to Phase I permitting. The permit decision deadlines set forth in subpart I shall apply to decisions on initial Phase II permit applications.

(2) Phase II permit renewals. The Administrator shall issue a permitting decision on Phase II permit renewal applications within 6 months of receipt of a complete renewal application meeting the requirements of this part, not including periods during which the source is required to provide additional information, unless the Administrator modifies this deadline.

(3) Even though a permit application for an affected source is deemed complete as provided in § 72.72(a), the deadline for the Administrator to make a permitting decision on the application shall not begin to run where the designated representative for the source subsequently fails to submit in a timely manner supplemental information required by a notice for supplemental information issued by the Administrator. The Administrator shall deny the application if the designated representative fails to submit the supplemental information required within the time required by the Administrator, not to exceed 12 months from the date the permit application was first submitted.

§ 72.71 Acid rain permit program forms.

The Administrator shall use the Acid Rain program forms specified in appendix C of this part in developing the Acid Rain permit. These forms include Acid Rain permit application forms, proposed compliance plan forms, and Acid Rain permit forms. The Administrator will submit the data contained in these forms through an automated system, the Acid Rain Permit program Electronic Application and Reporting System.

§ 72.72 Completeness.

(a) *Determination of completeness.* (1) The Administrator shall determine whether the application is complete within 30 days of receipt by the U.S. EPA Regional office for the Region in which the source is located. The application shall be deemed to be complete by operation of law if the Administrator fails to notify the designated representative to the contrary within 30 days of receipt.

(2) Effect of a determination of completeness. (i) If a designated representative has submitted an Acid Rain permit application that is determined by the Administrator to be complete under paragraph (a) of this section, but the Administrator has not yet issued a permit, each affected unit covered by the application shall as provided in § 72.53 be deemed to be in compliance with the prohibition in § 72.30(a)(1) of this part against operating without a permit; provided that any delay by the Administration in completing his or her review of the application is not due to a failure of the designated representative for the affected source to submit supplemental information required by the Administrator in a timely manner.

(ii) A permit application and proposed compliance plan determined to be complete under this section shall be binding on the designated representative, owners, and operators of the affected units at the source, and shall be enforceable against the affected source until a permit and approved compliance plan for the source is issued by the Administrator.

(3) The Administrator's determination under paragraph (a)(1) of this section shall be based on whether the application includes:

(i) All information required in § 72.31 (Information Requirements for Acid Rain Permit Applications);

(ii) All information required in § 72.32 (Acid Rain Compliance Plan Requirements) and subpart D of this part;

(iii) All certifications required in § 72.31(d);

(iv) All applicable information required in subpart C; and

(v) A complete certificate of representation pursuant to subpart B.

(4) No application shall be complete unless it is submitted on the standard forms in appendix C of this part or through the Acid Rain program Electronic Permitting Program System, as established by the Administrator.

(b) *Supplemental information.* (1) Notwithstanding a determination of completeness pursuant to paragraph (a) of this section the Administrator may require, by issuing a notice for supplemental information, submission of any additional information necessary to complete the application and proposed compliance plan and to enable the Administrator to issue a permit that complies with all the requirements of this part and 40 CFR parts 70, 71, and 73–78.

(2)(i) The designated representative shall submit the required information within 30 days of receiving a notice for supplemental information from the Administrator unless the Administrator allows for additional time in writing as reasonable for the designated representative to collect and submit the required information, not to exceed 60 days from the date the permit application was first submitted to the Administrator.

(ii) A failure to submit the supplemental information within the required time period shall result in a denial of the permit. Such denial shall be considered a permitting decision for purposes of any permit appeals pursuant to subpart H.

§ 72.73 Proposed permit.

(a) After the Administrator receives all supplemental information requested by notice, the Administrator shall issue or deny a proposed permit for the affected source.

(b) Each proposed Acid Rain permit shall set forth, expressly or by reference, and require compliance with:

(1) All applicable requirements specified in subpart E of this part including a proposed compliance plan.

and 40 CFR parts 73–78, including any appendices thereto;

(2) All applicable monitoring and reporting requirements set forth in 40 CFR part 75; and

(3) All applicable requirements concerning allowances, as set forth in 40 CFR parts 73 and 74.

(c) The proposed permit shall be based on the information submitted by the designated representative for the affected source and such other information as required by § 72.74 to be developed for the administrative record.

(d) The proposed permit shall be accompanied by a statement of basis in accordance with § 72.75.

(e) The application and compliance plan as approved or modified by the Administrator proposed permit shall continue to be binding on the source until the affected date of the permit issued by the Administrator for that source, in accordance with the deadlines specified in § 72.61(a)(1), or § 72.205(b)(1) and (2).

§ 72.74 Permit administrative record.

(a) *Applicability.* The Administrator shall prepare an administrative record for all proposed permits and permitting decisions.

(b) *Contents of the Permit Administrative Record.* (1) The administrative record for a proposed permit shall include:

(i) The permit application, the proposed compliance plan, and any supporting data submitted by the designated representative;

(ii) The proposed permit;

(iii) A statement of basis as described in § 72.75;

(iv) Copies of all documents cited in the statement of basis, or the location of these documents; and

(v) Other documents relied on by the Administrator to develop the proposed permit, including any records of discussions or conferences with the permittee or other interested persons regarding the proposed permit.

(2) The administrative record for any permitting decision shall include:

(i) The permitting decision including any approved compliance plan;

(ii) The administrative record for the proposed permit;

(iii) Copies of all written public comments submitted on the proposed permit;

(iv) The record of any public hearing on the proposed permit;

(v) Any response to public comments submitted on the proposed permit as required by § 72.79, including any documents cited in the response; and

(vi) Any data, reports, or other materials submitted to, or generated by, the Administrator, during the public comment period that were considered by the Administrator in making a permitting decision.

§ 72.75 Statement of basis.

(a) The Administrator shall prepare a statement of basis for every proposed permit. The statement of basis shall briefly set forth significant factual, legal, and policy considerations relied on by the Administrator in preparing the proposed permit. The Administrator shall send the statement of basis to the designated representative and, on request, to any other person.

(b) The statement of basis shall include:

(1) References to applicable statutory or regulatory provisions and to the administrative record;

(2) Reasons why any alternative methods of compliance, alternative emissions limitations, or alternative monitoring procedures requested in the permit application have or have not been approved;

(3) A description of the procedures that will be followed for issuing the permit including:

(i) The beginning and ending dates of the public comment period under § 72.76;

(ii) The address where public comments must be submitted;

(iii) Procedures for requesting a public hearing, and the rules that will govern the hearing, if any; and

(iv) Any other procedures by which the public may participate.

(4) The name, telephone and facsimile number of a person at EPA who can be contacted for additional information.

§ 72.76 Opportunities for public comment on proposed permits.

(a) *Generally.* (1) The Administrator shall give public notice of the following:

(i) Any proposed permit and its availability for public review and comment;

(ii) Opportunity to request a public hearing on a proposed permit pursuant to § 72.78;

(iii) Any scheduled hearing granted pursuant to § 72.78; and

(iv) The reopening of a permit for cause pursuant to 40 CFR part 70.

(2) Any public notice of a proposed permit given under this subpart may be for one or more proposed permits.

(b) *Timing.* Public notice under this subpart shall provide for:

(1) A 30-day public comment period, beginning from the date of publication of the notice of a proposed permit; and

(2) An opportunity to request a public hearing on the proposed permit, including a scheduled date and place for the hearing if requested, to occur not earlier than 15 days after the notice is given.

(c) *Methods.* The Administrator shall give the public notice of the proposed permit required by this section, as follows:

(1) Actual notice shall be given to the following persons (except to the extent any such person has waived his or her right to receive such notice for any class or category of permit action):

(i) The designated representative;

(ii) The State or local air pollution agency and the State utility rate regulatory authority (if any) with jurisdiction over the affected source governed by the proposed permit;

(iii) In accordance with title V of the Act, the State or local air pollution agency for any contiguous State whose air quality may be affected by the affected source that is the subject of the permit action, or for any State located within a 50-mile radius of the affected source; and

(2) Notice by publication in the **Federal Register** and in a journal of general circulation in the area affected by the proposed permit, as provided in 40 CFR 70.8.

(d) *Contents.* All public notices issued under this part shall contain the following information:

(1) Name and address of the EPA office processing the proposed permit for which the notice is being given;

(2) Name, address, telephone and facsimile number of the designated representative for the affected source;

(3) Identification of each affected unit at the source covered by the proposed permit as follows: name (plant, unit), address;

(4) A brief description of the action proposed to be taken; including for proposed permits:

(i) The basic allowance allocation for the affected unit or units covered by the permit;

(ii) Any alternative methods of compliance that are proposed to be approved; and

(iii) Any alternative monitoring system that is proposed to be approved.

(5) The address and office hours of a public location where the administrative record is available for public inspection; and a statement that all information submitted by the designated representative and not protected as confidential pursuant to section 114(c) of the Act is available for public inspection as part of the administrative record;

(6) Name, address, telephone and facsimile number of the EPA office from whom interested persons may obtain further information;

(7) A brief description of the public comment procedures, including:

(i) Explanation of the purpose of the public comment opportunity;

(ii) The time allowed for public comments;

(iii) Where public comments should be sent;

(iv) Required formats and contents for public comment;

(v) The location, date, time, and procedures of any scheduled public hearing; and

(vi) Any other procedures by which the public may participate.

(e) *Extensions and reopenings of the public comment period.* On the Administrator's own motion, or on the request of any person, the Administrator may, at his or her discretion, extend or reopen the public comment period where it reasonably appears that doing so will expedite the decision-making process. Notice of any such extension or reopening shall be given pursuant to this section.

§ 72.77 Public comments.

(a) *General.* (1) Any person may submit comments on a proposed permit.

(2) Comments shall be submitted during the public comment period. Comments received after the public comment period has closed will not be considered.

(b) *Form.* (1) Comments shall be submitted in duplicate.

(2) The submission shall clearly indicate the proposed permit to which the comments apply.

(3) The submission shall clearly indicate the name of the person commenting, and his or her interest, and affiliation, if any, to the permittee.

(c) *Contents.* Comments may be made on any aspect of the proposed permit.

(1) Except as provided in paragraph (c)(2) of this section, timely comments will be considered when making a permitting decision.

(2) Comments will not be considered if they concern issues not related to the permit, or Acid Rain issues clarified by the Act or addressed or codified into regulation, including but not limited to any standard permit conditions specified in § 72.54 of this part, standard allowance requirements pursuant to the Act and 40 CFR parts 72 through 78, monitoring requirements pursuant to 40 CFR part 75, the environmental effects of Acid Rain, acid deposition, sulfur dioxide or nitrogen oxides generally, or of actions on other permit application not related to the permit action in question. Generally comments concerning permit issuance procedures will not be considered. Specifically comments concerning the issuance of the proposed permit, such as requests for a public hearing on the permit, will be considered.

(3) Persons who do not wish to raise issues on the proposed permit action, but who wish to be notified of any subsequent permit actions concerning the permit may so indicate in writing during the public comment period or at any other time, and their names shall be placed by the Administrator on a list of interested persons.

§ 72.78 Opportunity for public hearing.

(a) During the public comment period provided under § 72.76, any person may request a public hearing. A request for a public hearing shall be made in writing and shall state the nature of the issues proposed to be raised in the hearing.

(b) The Administrator may, at his or her discretion, hold a public hearing whenever the Administrator finds that:

(1) A request for such has been made that raises significant issues affecting the terms and conditions of the permit and such hearing would contribute to the permitting exercise; or

(2) A hearing might clarify one or more issues raised by the proposed permit.

(c) Public notice of the scheduling of a public hearing shall be given as specified in § 72.76.

(d) During a public hearing under this section, any person may submit oral or written comments concerning the proposed permit. The Administrator may set reasonable limits on the time allowed for oral statements, shall require the submission of written summaries of each oral statement, and may extend the public comment period by so stating during the hearing.

(e) The Administrator shall assure that a record is made of the hearing, which shall be made part of the administrative record.

§ 72.79 Response to comments.

(a) The Administrator shall consider comments received during the public comment period and shall respond in writing to such comments when issuing the permitting decision.

(b) The response to comments shall:

(1) Identify any permit provision which has been changed in the permitting decision in response to comments made, and the reasons for the change; and

(2) Briefly describe and respond to comments on the proposed permit.

(c) Any documents cited in the response to comments shall be included in the administrative record, or their location shall be cited, if readily obtainable.

§ 72.80 Issuance and effective date of acid rain permits.

(a) After the close of the public comment period, the Administrator shall make a permitting decision. The Administrator shall give actual notice of the permitting decision to the designated representative for the affected source, and to any persons who submitted comments during the public comment period or who are entitled to actual notice under § 72.76(c)(1). The Administrator shall also give notice of the permitting decision in the **Federal Register**.

(b) Any permitting decision issued under this subpart shall become final agency action 60 days after notice of the permitting decision is published in the **Federal Register**, unless an appeal is filed pursuant to subpart H.

(c) The term of every Acid Rain permit shall be 5 years.

§ 72.81 Permit renewals.

(a) Permit renewals shall be issued subject to the same procedural and substantive requirements of this part applicable to Acid Rain permit issuance.

(b) Acid Rain permit renewal applications and proposed compliance plans submitted for shall comply with the requirements of subparts C and D of this part.

(c) Acid Rain permit renewals and approved compliance plans shall comply with all requirements of this subpart and subpart D.

(d) Consistent with subpart C, the designated representative shall apply for an Acid Rain permit renewal at least 18 months prior to the expiration of the affected source's existing permit: *provided* That the Administrator may modify this deadline for good cause shown.

Subpart H—Federal Appeal Procedures for Acid Rain Permits

§ 72.90 General.

(a)(1) This subpart shall govern appeals of all Acid Rain permitting decisions of the Administrator.

(2) Any interested person may file an appeal with the Administrator of such permitting decision within 60 days of its issuance. The Administrator shall, in his or her discretion, either:

(i) Decide the appeal. Such decision shall be deemed final Agency action for purposes of judicial review under Section 307 of the Act; or

(ii) Where there is a disputed issue of fact material to contested portions of the permitting decision, refer the proceeding to an Administrative Law Judge who shall conduct an evidentiary hearing to

decide the disputed issue of fact. The Administrative Law Judge shall issue a proposed decision which, unless contested, shall become final Agency action. If the proposed decision is contested, the Administrator shall issue a decision which shall be deemed final Agency action.

(b) Applicability. The permit appeal procedures and evidentiary hearing procedures of this subpart shall be available to challenge any of the following permitting decisions of the Administrator under the Acid Rain program:

(1) The issuance or denial by the Administrator of a permit under this part;

(2) The Administrator's approval or disapproval of a proposed excess emissions offset plan under 40 CFR part 77;

(3) A determination by the Administrator of whether a demonstration required under this part, or a proposed technology meets the criteria for approval of a compliance option under subpart D, including a determination under § 72.44 whether a proposed technology is a qualifying repowering technology; and

(4) Any other permitting decision of the Administrator.

(c) The following decisions of the Administrator under the Acid Rain program shall not be appealable pursuant to this subpart:

(1) Receipt and reliance on a certificate of representation submitted by a designated representative in accordance with subpart B of this part;

(2) Approval or disapproval of a proposed alternative emissions monitoring system under 40 CFR part 75; and

(3) Any other action of the Administrator under 40 CFR parts 73–76.

(d) A petitioner appealing a permitting decision under this subpart shall file a petition for review with the U.S. EPA, Office of the Administrator c/o the Chief Judicial Officer (CJO), with copies sent to the U.S. EPA Acid Rain Division, the U.S. EPA Regional Office for the Region in which the affected unit is located, and with the State air management agency for the State where the permitted source is located at the respective addresses provided in § 72.4.

§ 72.91 Petition for review and request for evidentiary hearing.

(a) The following persons may petition for review of a permitting decision of the Administrator, and may include in the petition a request for evidentiary hearing:

(1) The designated representative for the affected source; or

(2) Any interested person.

(b) Within 30 days following issuance of a permitting decision by the Administrator under this part or 40 CFR parts 73–76, any person meeting the criteria under paragraph (a) of this section may file a petition with the Administrator for review of the decision, which may include a request for an evidentiary hearing to resolve any disputed issue of material fact concerning the permitting decision. That person shall simultaneously serve a copy of the petition on each interested person and on the designated representative of the source covered by the permit unless the designated representative is the petitioner.

(c) The petition for review under this subpart shall state with specificity:

(1) Each material factual and legal issue alleged to be in dispute, and any such factual issue for which an evidentiary hearing is sought;

(2) A clear and concise brief in support of the petition, explaining why the factual or legal issues are material, and, if an evidentiary hearing is requested, why direct and cross-examination of witnesses is necessary to resolve such factual disputes;

(3) The time estimated to be necessary for an evidentiary hearing, if requested, and a proposed expeditious schedule for a hearing providing for the hearing to commence not later than 6 months after the petition is granted;

(4) The name, mailing address, telephone and facsimile number of the person filing the petition;

(5) A clear and concise statement of the nature and scope of the interest of the petitioner;

(6) The names and addresses of all persons whom the petitioner will represent in the proceeding;

(7) A certified statement by the petitioner that, in the event of an evidentiary hearing, upon the motion of any party granted by the Presiding Officer, or upon order of the Presiding Officer sua sponte, and without cost or expense to any other party, any of the following persons shall be available to appear and testify:

(i) The petitioner;

(ii) Any person represented by the petitioner; and

(iii) Any officer, director, employee, consultant, or agent of the petitioner.

(8) Specific references to the contested portions of the permitting decision;

(9) Any revised or alternative action of the Administrator sought by the petitioner as necessary to implement the requirements, purposes, or policies of title IV of the Act, including revised permit provisions or a denial of the permit.

(10) Identification of any contested decision or permit provision that the petitioner believes should be stayed pending resolution of the appeal.

(d) In no event shall a petition for review under this subpart be filed with regard to any standard permit provision set forth in § 72.54 of this part.

(e) Within 30 days after a petition for review is filed, any person meeting the requirements of paragraph (a) of this section may file a response to the petition.

§ 72.92 Filing and submission of documents.

(a) All original submissions made under this subpart shall be signed by the person making the submission, or by an attorney or other authorized agent or representative. In the case of an affected unit, all submissions shall be signed by the designated representative. The name, address, telephone number, facsimile number (if any), and representative capacity (if any) of the person making the submission shall be provided with the submission.

(b)(1) All data and information referred to or in any way relied upon in any submission made under this subpart shall be included in full, and may not be incorporated by reference, unless previously submitted as part of the administrative record for the permitting decision;

(2) Notwithstanding paragraph (b)(1) of this section, State or Federal statutes and regulations, judicial decisions published in a national reporter system, officially issued EPA documents of general applicability, and any other publicly and generally available reference material may be incorporated. Any party incorporating materials referred to in this paragraph into a submission under this subpart by reference shall provide copies of the materials upon request, and as instructed by, the Administrator or the Presiding Officer.

(3) If any part of any submission is in a foreign language, it shall be accompanied by an English translation verified by the person making the translation, under oath, to be complete and accurate, together with the name, address, and a brief statement of the qualifications of the person making the translation. Translations submitted of material originally produced in a foreign language shall be accompanied by copies of the original material.

(4) Where relevant data or information is contained in a document also containing irrelevant matter, either

the irrelevant matter shall be deleted or an index to the relevant portions of the document shall be included in the document.

(5) Failure to comply with the requirements of this section or any other requirement in this subpart may result in the noncomplying portions of the submission being excluded from consideration. If the Administrator or the Presiding Officer, determines on motion by any party or sua sponte, that a submission fails to meet any requirement of this subpart, the Administrator or Presiding Officer may return the submission, together with a reference to the applicable requirements on which the determination is based. A party whose materials have been rejected has 7 days, from the date the materials are returned to correct the materials in conformance with this subpart and resubmit them, unless the Administrator or Presiding Officer authorizes, on the basis of good cause shown, a longer time.

(c) The filing of a submission shall not mean or imply that the submission, in fact, meets all applicable requirements, that the submission contains reasonable grounds for the action requested, or that the action requested is in accordance with law.

(d) An original and two copies of any written submission relating to a review under this subpart submitted after notice of the granting of a petition for review is published pursuant to § 72.97, shall be filed with the Administrator and, in the event a request for a hearing is granted pursuant to § 72.9, with the Hearing Clerk (except where the Presiding Officer has requested that the copy be served on the Presiding Officer).

(e) The party filing any submission in a proceeding under this subpart shall also serve a copy of the submission upon the designated representative of each unit involved in the permitting decision and upon each party to the proceeding.

(f) Every submission filed with the Administrator, Presiding Officer, or Hearing Clerk under this subpart shall be accompanied by a certificate of service citing the date, place, time, and manner of service on each party of record to the proceeding and the names of the persons served.

(g) The Hearing Clerk shall maintain and furnish, to any person upon request, a list containing the name, service address, telephone, and facsimile numbers of each party of record to a proceeding under this subpart and their attorneys or duly authorized representatives.

(h) Affidavits shall be made on personal knowledge and belief, shall set forth only those facts that would be admissible into evidence under § 72.93 of this part, and shall show affirmatively that the affiant is competent to testify to the matters stated therein.

§ 72.93 Limitation on submitting new evidence and raising new issues.

(a) No evidence shall be submitted, or issues raised, in an appeal by any party under this subpart that were not submitted or raised during the public comment period on the permitting decision that is the subject of the appeal, absent a showing of good cause explaining the party's failure to make such submission or raise such issue. Good cause shall include any instance where the party seeking to submit new evidence or raise a new issue shows that the evidence or issue could not have reasonably been ascertained, submitted, or raised, or that the materiality of the new evidence or issue could not have reasonably been anticipated, prior to the close of the public comment period.

(b) If an evidentiary hearing is granted, no evidence shall be submitted on questions of law or policy or on matters not subject to challenge in the evidentiary hearing.

§ 72.94 Decision on petition for review.

(a) The Administrator shall grant or deny any petition for review (including any request for evidentiary hearing) under this part within 30 days of the date by which persons may file responses to the petition under § 72.91(e). If the Administrator fails to act on the petition within 90 days of filing, that petition shall be deemed to be granted.

(b) The Administrator may grant a request for an evidentiary hearing if he or she finds that there are disputed issues of fact material to contested portions of the permitting decision, and if he or she also determines, in his or her discretion, that an opportunity for direct- and cross-examination of witnesses is necessary in order to resolve these factual issues.

(c) The evidentiary hearings on all petitions that are granted with regard to a particular permitting decision shall be consolidated and shall commence no later than 6 months following the granting of the request.

(d) If a petition for review is denied by the Administrator, in whole or in part, the Administrator shall briefly specify in writing the reasons for the denial. The denial shall be a final Agency action subject to review under section 307 of the Act.

(e) If a petition for review is granted by the Administrator but no evidentiary hearing will be held, the Administrator shall issue a decision pursuant to § 72.108(c). The standard of review set forth at § 72.100 shall govern the decision of the Administrator.

(f) If the Administrator grants a petition for an evidentiary hearing, in whole or in part, he or she shall identify the portions of the permitting decision that have been contested by the petitioner and with regard to which any evidentiary hearing has been granted. Portions of the permitting decision that are not contested or for which the Administrator has denied the petition for review shall not be considered at the evidentiary hearing.

(g) To the extent that a request for an evidentiary hearing is granted for certain disputed factual issues, the Administrator shall refer the petition to the Chief Administrative Law Judge and, at his or her discretion, may also refer for decision all or a portion of the remaining legal or factual issues for review to the Chief Administrative Law Judge.

(1) The Chief Administrative Law Judge shall thereafter designate an Administrative Law Judge as Presiding Officer to conduct the evidentiary hearing. In addition, upon granting a request for an evidentiary hearing, the Administrator shall designate the EPA trial staff.

(2) If all parties to such a hearing waive in writing their statutory right to have an Administrative Law Judge named as the Presiding Officer in a hearing subject to this subpart, the Chief Administrative Law Judge may name a lawyer permanently or temporarily employed by the Agency and without any prior connection with the proceeding to serve as Presiding Officer.

§ 72.95 Stays of contested acid rain requirements pending appeal.

(a) A contested permitting decision of the Administrator may be stayed, in whole or in part consistent with paragraph (b) of this section, by the Administrator or the Presiding Officer upon request or sua sponte during an appeal proceeding under this subpart only to the extent necessary to prevent irreparable injury pending final Agency action.

(b) The following permit requirements shall in no event be stayed due to any appeal of the Administrator's permitting decision and shall be fully effective and enforceable:

(1) The requirement that an affected unit hold as of the allowance transfer deadline, sufficient allowances in its Allowance Tracking System compliance subaccount to cover its sulfur dioxide

emissions in the preceding calendar year;

(2) The allowance allocations for any year during which the appeal proceeding is pending or is being conducted;

(3) Any standard Acid Rain permit condition as specified in § 72.54 of this part;

(4) The emissions monitoring requirements applicable to the affected source pursuant to 40 CFR part 75;

(5) Uncontested provisions of the permitting decision; and

(6) The terms of a certificate of representation submitted pursuant to subpart B.

(c) The permit shield as provided under § 72.53 shall continue to be in effect.

(d) The Administrator shall specify which provisions of the permitting decision shall be stayed.

§ 72.96 Consolidation and severance of appeals proceedings.

(a) The Administrator or Presiding Officer has the discretion to consolidate, in whole or in part, two or more proceedings under this subpart whenever it appears that a joint proceeding on any or all of the matters at issue in the proceedings would be in the interest of justice, would expedite or simplify consideration of the issues, and would not prejudice any party of record. Consolidation of proceedings under this paragraph shall not affect the right of any party to raise issues that might have been raised had there been no consolidation.

(b) The Administrator or Presiding Officer has the discretion to sever issues or parties from a proceeding under this subpart whenever it appears that separate proceedings would be in the interest of justice, would expedite or simplify consideration of the issues, and would not prejudice any party of record.

§ 72.97 Notice of the grant of petition for review.

Notice that a petition for review (including any request for an evidentiary hearing) of a permitting decision of the Administrator has been granted shall be published in the **Federal Register**. In addition, a copy of the notice shall be mailed to all interested persons.

§ 72.98 Ex parte communications during pending of a hearing.

(a)(1) No interested person outside EPA or member of the EPA trial staff shall make or knowingly cause to be made to any member of the decisional body an ex parte communication on the merits of a proceeding under this subpart.

(2) No member of the decisional body shall make or knowingly cause to be made to any interested person outside the EPA or to any member of the EPA trial staff, an ex parte communication on the merits of any proceeding under this subpart.

(3) A member of the decisional body who receives or who makes or who knowingly causes to be made an ex parte communication prohibited by this paragraph shall file with the Hearing Clerk for inclusion in the record of the proceeding under this subpart all written ex parte communications or a memoranda stating the substance of any oral communication together with all written responses and memoranda stating the substance of all oral responses.

(b) Whenever any member of the decisional body receives an ex parte communication made or knowingly caused to be made by a party or representative of a party to a proceeding under this subpart, the person presiding over the proceedings then in progress may, to the extent consistent with justice, require the party to show good cause why its claim or interest in the proceedings should not be dismissed, denied, disregarded, or otherwise adversely affected on account of these violations.

(c) The prohibitions of this section shall begin to apply upon issuance by the Administrator of the notice of the granting of a petition under § 72.97. This prohibition terminates at the date of final Agency action.

§ 72.99 Intervenors.

(a) Any interested person may submit a motion for leave to be admitted as an intervenor in any appeal proceeding (including any evidentiary hearing under this subpart) no later than 15 days after notice is given under § 72.97 that the petition for review has been granted or after notice is given under § 72.108(c) that a proposed decision following an evidentiary hearing will be reviewed. A motion for leave to intervene under this section shall set forth the grounds for the proposed intervention. Late motions may be granted only for good cause shown.

(b) The Administrator or Presiding Officer shall grant a motion to intervene only upon an express finding that:

(1) The motion to intervene raises matters relevant to the factual or legal issues to be reviewed.

(2) The intervenor has demonstrated a substantial interest in the outcome of the pending proceeding.

(3) The intervenor has consented to be bound by:

(i) Prior stipulations by and between the existing parties; and

(ii) All orders previously entered in the proceeding.

(4) Intervention would promote the interests of justice and will not cause undue delay or prejudice to the rights of the existing parties.

§ 72.100 Standard of review.

On appeal of a permitting decision of the Administrator, the petitioner shall have the burden of going forward and of persuasion to show that a finding of fact or conclusion of law underlying the permitting decision is clearly erroneous or that an exercise of discretion or policy determination underlying the permitting decision is arbitrary and capricious or otherwise warrants review.

§ 72.101 Scheduling orders and pre-hearing conferences.

(a) Once a request for an evidentiary hearing has been granted, the Presiding Officer shall issue an order setting a hearing and pre-hearing motions schedule. The Presiding Officer may also, on request or sua sponte, direct the parties to appear at a specified time and place for one or more pre-hearing conferences. The order shall schedule:

(1) The submission by each party of a narrative statement of position on each factual issue in controversy;

(2) The submission of written testimony, list of witnesses, and other evidence in support of those statements; and

(3) The submission of any requests by any party for the production of documentation, data, or other information material to the disputed facts to be addressed at the hearing.

(b) The pre-hearing conference may address the following matters:

(1) Simplification, clarification, amplification, or limitation of the issues.

(2) Admissions and stipulations of facts, and determinations of the genuineness of documents.

(3) Objections to the introduction into evidence at the hearing of any written testimony or other submissions proposed by a party; *provided* that at any time before the end of the hearing, any party may make, and the Presiding Officer shall consider and rule upon, a motion to strike testimony or other evidence, other than the administrative record, on the grounds of relevance, competency, or materiality.

(4) Taking official notice of any matters.

(5) Grouping of parties with substantially similar interests to eliminate redundant evidence, motions, objections, and briefs.

(6) Such other matters that may expedite the hearing or aid in the disposition of matters in dispute.

(c) At a prehearing conference or at such other time set by the Presiding Officer:

(1) Each party shall make available to all other parties of record the names of any witnesses it expects to call. At the request of the Presiding Officer, the party shall include a brief narrative summary of any witness's expected testimony.

(2) The administrative record and copies of any written testimony, documents, papers, exhibits, or materials that a party expects to introduce into evidence shall be marked for identification as ordered by the Presiding Officer.

(d) Expected witnesses, testimony, and other evidence may be changed at any time before the end of a hearing upon order of the Presiding Officer for good cause shown.

(e) The Presiding Officer shall issue a written order (which may be in the form of a transcript) reciting the actions taken at each conference and setting forth the schedule for any hearing. The order shall include a statement of the areas of factual and legal agreement and disagreement and the methods and procedures to be used in developing the evidence. This order shall control the subsequent course of the proceeding unless modified by the Presiding Officer for good cause shown.

§ 72.102 Evidentiary hearing procedure.

(a) If a petition for an evidentiary hearing is granted, the Presiding Officer shall conduct a fair and impartial hearing on the record, take action to avoid unnecessary delay in the disposition of the proceedings, and maintain order. For these purposes, the Presiding Officer may:

(1) Hold pre-hearing conferences under § 72.101;

(2) Administer oaths and affirmations;

(3) Regulate the course of the hearings and govern the conduct of participants;

(4) Examine witnesses;

(5) Identify and refer issues for interlocutory decision under § 72.107;

(6) Rule on, admit, exclude or limit evidence;

(7) Establish the time for filing motions, testimony, and other written evidence, briefs, and other submissions;

(8) Rule on motions and other pending procedural matters, including but not limited to motions for summary disposition in accordance with § 72.103;

(9) Order that the hearing be conducted in stages whenever the number of parties is large or the issues are numerous and complex;

(10) Allow such direct and cross-examination of witnesses for which testimony was submitted, as provided in the scheduling order under § 72.101(a), as may be necessary to resolve disputed issues of material fact; provided that no direct or cross-examination shall be allowed on questions of law or policy, or regarding matters that are not subject to challenge in the evidentiary hearing; and *Provided Further* that the party seeking the direct or cross-examination has the burden of demonstrating that these standards have been met; and

(11) Allow the hearing to be open to the public. Where the Presiding Officer determines that the hearing should be open to the public, he or she shall provide notice in the **Federal Register** and actual notice to the designated representative and all interested persons no later than 15 days prior to commencement of the hearing; and

(12) Take any other action not inconsistent with the provisions of this subpart for the maintenance of order at the hearing and for the expeditious, fair, and impartial conduct of the proceeding.

(b) All direct and rebuttal evidence at an evidentiary hearing shall be submitted in written form, unless, upon motion and good cause shown, the Presiding Officer, in his or her discretion, determines that oral presentation of the evidence on any particular factual issue will materially assist in the efficient resolution of the issue.

(c)(1) The Presiding Officer shall admit all evidence which is not irrelevant, immaterial, unduly repetitious, or otherwise unreliable or of little probative value. Evidence relating to settlement that would be excluded in the Federal courts under Rule 408 of the Federal Rules of Evidence, shall not be admissible.

(2) Whenever any evidence or testimony is excluded by the Presiding Officer as inadmissible, all such evidence shall remain a part of the record as an offer of proof. The party seeking the admission of oral testimony may make an offer of proof by means of a brief statement on the record describing the testimony excluded.

(3) When two or more parties have substantially similar interests and positions, the Presiding Officer may limit the number of attorneys or other party representatives who will be permitted to cross-examine and to make and argue motions and objections on behalf of those parties.

(4) Rulings of the Presiding Officer on the admissibility of evidence or testimony, the propriety of cross-examination, and other procedural matters shall appear in the record of the hearing, and shall control further proceedings unless reversed as a result of an interlocutory appeal taken under § 72.107.

(5) All objections shall be made promptly or be deemed waived. Parties shall be presumed to have taken exception to an adverse ruling. No objection shall be deemed waived by further participation in the hearing.

§ 72.103 Motions in evidentiary hearings.

(a) Any party may file a motion with the Presiding Officer on any matter relating to the evidentiary hearing in accordance with the scheduling order issued under § 72.101(a). All motions shall be in writing and served as provided in this section except those made on the record during an oral hearing before the Presiding Officer.

(b) Any party to an evidentiary hearing may make a motion for a summary disposition in its favor on any factual issue on the basis that there is no genuine issue of material fact. When a motion for summary disposition is made and supported, any party opposing the motion may not rest upon mere allegations or denials, but must show, by affidavit or by other materials subject to consideration by the Presiding Officer, that there is a genuine issue of material fact.

(c) Within 10 days after service of any written motion, any party may file a response to the motion. The time for response may be shortened to no less than 1 day or extended by up to 20 days by the Presiding Officer for good cause shown.

(d) The Presiding Officer may schedule an oral argument and call for the submission of briefs on any motion. The Presiding Officer shall rule on the motion in writing not more than 30 days after the later of the date that responses to the motion may be filed under paragraph (c) of this section or that the oral argument or submission of briefs is completed.

(e) If all factual issues are decided by summary disposition prior to the hearing, no hearing will be held and the Presiding Officer shall issue a proposed decision under § 72.106. If a summary disposition is denied or if partial summary disposition is granted, the hearing shall proceed on the remaining issues.

§ 72.104 Record of appeal proceeding.

(a) The proposed decision issued by the Presiding Officer, transcripts of oral hearings or oral arguments, written direct and rebuttal testimony, and any other written material of any kind submitted in the proceeding shall be

part of the record and shall be available to the public, in the office of the Hearing Clerk, as soon as it is received in that office.

(b) Hearings and oral arguments shall be recorded as specified by the Presiding Officer, and thereupon transcribed. After the hearing or oral argument, the reporter shall certify and file with the Hearing Clerk:

(1) The original transcript, and

(2) Any exhibits received or offered into evidence at the hearing.

(c) The Hearing Clerk shall promptly notify each of the parties of the filing of the certified transcript of the proceedings. Any party who desires a copy of the transcript may obtain a copy from the Hearing Clerk upon payment of costs.

(d) The Presiding Officer shall allow witnesses, parties, and their counsel an opportunity to submit written proposed corrections of the transcript necessary to correct errors made in the transcribing. No more than 7 days shall be allowed for submitting such corrections from the day a complete transcript of the hearing becomes available. Such corrections shall be incorporated into the certified transcript along with any objections made to proposed corrections filed within 7 days of the submission of the corrections.

§ 72.105 Proposed findings and conclusions and supporting brief.

Within 45 days after the certified transcript of the hearing is filed, any party may file with the Hearing Clerk proposed findings and conclusions on the issues referred to the Presiding Officer and a brief in support thereof. Briefs shall contain appropriate references to the record. A copy of these findings and conclusions and brief shall be served upon all other parties of record and the Presiding Officer. The Presiding Officer, for good cause shown, may extend the time for filing and may allow reply briefs.

§ 72.106 Proposed decision.

(a) The Presiding Officer shall review and evaluate the record, including the proposed findings and conclusions and any briefs filed by the parties, and shall issue and file a proposed decision on the factual and legal issues referred by the Administrator for decision under § 72.94(g), accompanied by findings of fact and proposed conclusions of law, as appropriate, with the Hearing Clerk within 60 days after the hearing is completed. The Hearing Clerk shall immediately serve copies of the proposed decision upon all parties of record and upon the Administrator.

(b) The proposed decision of the Presiding Officer shall automatically become the final decision 30 days after its service unless within that time:

(1) A party files objections with the Administrator pursuant to § 72.108(b), or

(2) The Administrator sua sponte files a notice that he or she will review the decision pursuant to § 72.108(c).

§ 72.107 Interlocutory appeal.

(a) Interlocutory appeals from orders or rulings of the Presiding Officer made during the course of a proceeding may be taken if the Presiding Officer certifies those orders or rulings to the Administrator for interlocutory appeal on the record. Requests to the Presiding Officer for certification of an interlocutory appeal must be filed in writing within 10 days of notice of the order or ruling and shall state briefly the grounds for the request.

(b) The Presiding Officer shall act on requests for interlocutory appeals within 15 days, and may certify an order or ruling for interlocutory appeal to the Administrator if:

(1) The order or ruling involves an important question on which there is substantial ground for difference of opinion, and

(2) Either:

(i) An immediate appeal of the order or ruling will materially advance the ultimate completion of the proceeding, or

(ii) A review after the proceeding is completed will be inadequate or ineffective.

(c) If the Administrator decides that certification was improperly granted, he or she shall decline to hear the appeal. The Administrator shall accept or decline all interlocutory appeals within 30 days of their submission. If the Administrator takes no action within that time, the appeal shall be automatically dismissed without prejudice.

(d) When the Presiding Officer declines to certify an order or ruling to the Administrator for an interlocutory appeal, the order or ruling may be reviewed by the Administrator only upon an appeal of the proposed decision following completion of the proceedings before the Presiding Officer, except when the Administrator determines, upon motion of a party and in exceptional circumstances, that to delay review would not be in the public interest. Such motion shall be made within 5 days after receipt of notification that the Presiding Officer has refused to certify an order or ruling for interlocutory appeal to the Administrator.

(e) The failure of a party to request an interlocutory appeal shall not prevent an appeal of an order or ruling as part of an appeal of a proposed decision under § 72.108.

§ 72.108 Appeal of proposed decisions to the administrator.

(a) Within 30 days after the issuance of a proposed decision by a Presiding Officer under this subpart, any party of record may appeal any matter set forth in the proposed decision or any other order or ruling made during the proceeding to which the party objected during the proceeding before the Presiding Officer, by filing an objection with the Administrator. In its objection, the party must show that the order, ruling, or proposed decision is based on:

(1) A finding of fact or conclusion of law that is clearly erroneous; or

(2) A policy determination or exercise of discretion that is arbitrary and capricious.

(b) Within 30 days after issuance of a proposed decision of a Presiding Officer, the Administrator may issue, sua sponte, in his or her discretion a notice of intent to review such proposed decision. The Administrator shall serve such notice upon all parties to the proceeding.

(c) Within a reasonable time following the filing of an appeal pursuant to § 72.92, objections under paragraph (a) of this section, or of a notice of intent to review under paragraph (b) of this section, the Administrator shall issue an order affirming, reversing, modifying, or remanding the permitting decision or proposed decision, as appropriate. Prior to issuing this order, the Administrator may provide an opportunity for parties to file additional briefs.

(d) If a party timely files objection to a proposed decision or permitting decision or if the Administrator, sua sponte, orders a review, then final Agency action shall occur as follows:

(1) If the Administrator issues a final order affirming, reversing, or modifying the permitting decision or proposed decision, the permitting decision or proposed decision, supplemented or changed by the final order, shall become the final Agency action;

(2) If the Administrator issues a decision remanding the proceeding, then final Agency action occurs upon completion of the remanded proceeding, including any appeals to the Administrator of the remanded proceeding.

(e) If no party of record files an appeal within 30 days after the Presiding Officer's proposed decision, and the Administrator does not decide to review the proposed order sua sponte, then the

proposed decision shall become final Agency action.

Subpart I—Acid Rain Phase II Implementation

§ 72.200 Relationship to title V operating permit program.

(a) *Scope.* This subpart sets forth additional criteria for State permit program approval, the procedures that State permitting authorities with approved programs under this subpart and 40 CFR part 70 shall use in the absence of an approved State program, and the procedures the Administrator shall use to issue Phase II Acid Rain permits to affected sources.

(b) *Relationship to 40 CFR part 70 Operating Permit Program.* Each permitting authority with an affected source shall take permitting action in accordance with the requirements and procedures of this part and 40 CFR part 70 for the purpose of incorporating Acid Rain program requirements into each affected source's title V operating permit. This subpart imposes requirements for, and limits the discretion of, the permitting authority in the issuance of Phase II Acid Rain permit provisions. To the extent that the regulations of this part are inconsistent with the regulations at 40 CFR part 70, these regulations shall take precedence and shall govern the procedures and requirements for issuance, revision, reopening, and renewal of the Acid Rain portion of an operating permit and the procedures for appeals challenging the substantive requirements of the Acid Rain portion of the operating permit.

§ 72.201 Approval of state programs—general.

(a) To provide for Acid Rain permitting during Phase II, each State in which an affected unit is located shall submit in accordance with this section and 40 CFR part 70, an approvable permit program.

(b) The Administrator shall act on the proposed State operating permit program submissions in accordance with the schedule and procedures set forth in 40 CFR 70.4(e). The Administrator shall approve State programs that conform to the applicable requirements of this subpart and 40 CFR 70.4(b).

(c)(1) Upon approval of such program, for the units or sources subject to such approved program, the Administrator shall suspend the issuance of permits as provided in title V.

(2) The Administrator reserves the right to delegate the administration of the remainder of the Phase I program upon delegation of the operating permit program.

§ 72.202 State permit program approval criteria.

(a) *Non-interference with Acid Rain program.* The permitting program shall not include or implement any measure that would interfere with the Acid Rain program. State permit program restrictions on and interference with allowance trading shall be grounds for disapproval of its title V operating permits program. Measures and implementation that would constitute such interference, and are thus prohibited, include but are not limited to:

(1) Prohibitions on the acquisition or transfer of allowances by an affected unit located in the State or area under the jurisdiction of the permitting authority inconsistent with title IV;

(2) Restrictions on an affected unit's ability to sell or otherwise alienate its allowances inconsistent with title IV;

(3) Requirements that an affected unit maintain a reserve of allowances in excess of the level determined to be prudent by the State regulatory authority or other entity having utility rate regulatory authority over the affected unit;

(4) Failing to notify the Administrator of any State-level appeals to, or decisions covering, Acid Rain permit provisions that might affect Acid Rain program requirements;

(5) The issuance of an order by the permitting authority inconsistent with title IV interpreting Acid Rain program requirements as not applying to a source in whole or in part, or otherwise modifying the requirements;

(6) Withholding of approval of any compliance option that meets the requirements of title IV; or

(7) Any other measure that the Administrator determines would hinder the operation of the Acid Rain program.

(b) *Excess emissions offset plan.* The permitting authority shall not interfere with the Administrator's decision regarding an excess emissions offset plan. Such interference shall constitute grounds for the Administrator to withhold or withdraw approval of the permit program.

(c) *Acid Rain permit program forms.* In developing the Acid Rain portion of the operating permit, the permitting authority shall use the Acid Rain program forms specified in appendix C of this part and, if the permitting authority is participating in the Acid Rain Permit program Electronic Application and Reporting System, issue permits in accordance with such system. These forms include Acid Rain permit application forms, proposed compliance plan forms, Acid Rain permit forms, and Acid Rain compliance certification reporting forms.

(d) *Acid Rain permit.* (1) Content. (i) The permitting authority shall issue, as a stand alone subpart of each source's operating permit pursuant to 40 CFR part 70, a proposed Acid Rain permit subpart that incorporates all the permit requirements of subpart E of this part, including all monitoring requirements the standard Acid Rain permit provisions of subpart E.

(ii) Such proposed Acid Rain permit subpart shall assure that the source is required to meet all of its obligations under title IV of the Act and 40 CFR parts 72–78.

(2) Each proposed Acid Rain permit subpart, including the approved compliance plan, shall contain all applicable Acid Rain requirements and prohibitions, shall be a complete and segregable portion of the operating permit, and shall not depend for its interpretation on information contained in the permit application or in any other related documents, other than public documents.

(e) *Acid Rain permit issuance.* State issuance of Acid Rain permits follow the procedures established by the permitting authority pursuant to 40 CFR part 70, and this part, which shall include the following Acid Rain specific requirements:

(1) Permit application requirements. (i) Requirement to comply. The permitting authority shall require that the designated representative certified pursuant to subpart B for each affected source within its jurisdiction comply with all applicable permit application requirements of subparts C and D. Designated representatives shall be required to comply with the Acid Rain permit application deadlines specified in this section for original permits and the deadlines specified in 40 CFR part 70 for permit renewals.

(ii) Revised application. The designated representative may submit a revised Acid Rain permit application and proposed compliance plan at any time.

(iii) Effect of an Acid Rain permit application. Acid Rain permit applications and proposed compliance plans, including amendments and revisions thereto, submitted by the designated representative for an affected source in accordance with this part and title IV, shall be binding on the designated representative and the owners and operators of the affected source, and shall be enforceable as a permit, once it is deemed complete until

issuance of a permitting decision. The terms of the Acid Rain permit and approved compliance plan issued to the source shall thereafter supersede the Acid Rain permit application and proposed compliance plan.

(iv) Submission to the Administrator. The permitting authority shall submit a written notice of application completeness to the Administrator within 10 working days following a determination by the permitting authority that the application is complete.

(2) Draft Proposed Permit. (i) The permitting authority shall prepare a draft Acid Rain permit in accordance with this part that incorporates all the requirements of this subpart and subpart E.

(ii) The permitting authority shall prepare a statement of basis for the draft Acid Rain permit, consistent with the applicable requirements of § 72.75.

(3) Notice to Administrator. The permitting authority shall submit the draft Acid Rain permit to the Administrator, consistent with the requirements of 40 CFR 70.8(a). This submission requirement shall not be waived, and shall include the draft Acid Rain permit, as well as other relevant portions of the operating permit that may affect the Acid Rain permit conditions.

(4) Public notice and comment period. Public notice must be given in a journal of general and national circulation and to those required to receive notice pursuant to 40 CFR 70.8(b).

(5) Proposed permit. Following the public notice and comment period on a draft Acid Rain permit, the permitting authority shall incorporate all changes necessary and develop a proposed Acid Rain permit that conforms to the applicable requirements of this subpart and subpart E of this part.

(6) Submittal to Administrator. (i) The permitting authority shall submit the proposed Acid Rain permit to the Administrator in accordance with 40 CFR part 70.

(ii) The Administrator shall review the proposed Acid Rain permit consistent with the requirements of 40 CFR 70.8(c).

(7) Acid Rain permit issuance. Following the Administrator's review of a proposed permit, the permitting authority or, under the terms of 40 CFR 70.8(c), the Administrator, shall incorporate any required changes and shall issue or deny the Acid Rain portion of the permit.

(8) Effective date of Acid Rain permits. Each source's Acid Rain permit issued by a permitting authority under this section shall be effective for a period of 5 years.

(9) Designated representative requirements. In no case shall a draft, proposed, or final Acid Rain permit be issued unless a representative has been designated pursuant to a complete certificate of representation, submitted in accordance with subpart B of this part.

(10) Notwithstanding any State law providing that a permit must be issued by default after a specified time, no Acid Rain permit shall be issued until the Administrator and neighboring States have had an opportunity to review a proposed Acid Rain permit as provided in this section and in 40 CFR 70.8(e).

(11) The deadlines and requirements for a permitting authority to take action on an Acid Rain permit application during the transition between Phase I and Phase II of the Acid Rain program, are governed by this part and title IV of the Act. At all other times, the permitting authority shall issue a permit within 6 months of receiving a complete application in accordance with 40 CFR 70.7(a)(2).

(f) *Permit revisions.* In acting on any Acid Rain permit revision, the permitting authority shall follow the permit revisions procedures set forth at subpart J of this part.

(g) *Permit renewal.* (1) The renewal of an Acid Rain permit for an affected source shall be subject to all the requirements of this subpart pertaining to the issuance of permits.

(2) The Acid Rain permit renewal application and proposed compliance plan submitted in accordance with this part and Title IV of the Act shall be binding on the designated representative for the source and shall be enforceable as a permit in the event that an Acid Rain permit expires prior to renewal, upon a determination of completeness by the permitting authority.

(h) *New owners.* Acid Rain permits shall be binding on any new owner or operator of a source by operation of law consistent with the requirements of subpart B of this part.

(i) *Acid Rain appeal procedures.* (1)(i) Appeals of Acid Rain permitting provisions in permits issued by the State that are not decisions of the Administrator as set forth in § 72.90(c), shall be conducted according to procedures established by the State pursuant to 40 CFR 70.4(b)(3)(x); *Provided* that no appeal of the Acid Rain portion of a permit shall be allowed more than 60 days following permit issuance or such shorter period as provided by the applicable State appeals procedures. Any change in the permit as a result of a State-level appeal shall be subject to the review procedures established under 40 CFR 70.8.

(ii) Notwithstanding paragraph (i)(1)(i) of this section, where the issue being appealed concerns a decision of the Administrator that has been incorporated into the State-issued permit, such appeal shall be brought under subpart H of this part only.

(2) The permitting authority shall provide actual notice to the Administrator of any State administrative or judicial appeal concerning an Acid Rain provision of any permit within 30 days of filing of the appeal.

(3) The State administrative and judicial permit appeals procedures shall ensure that the Administrator may intervene as a matter of right in any permit appeal involving an Acid Rain permit provision.

(4) The permitting authority shall provide actual notice to the Administrator of any determination or order in a State-level administrative or judicial proceeding that interprets, modifies, voids, or otherwise relates to any portion of an Acid Rain permit. Following any such determination or order, the Administrator shall have an opportunity to review and veto the permit or revoke the permit for cause pursuant to 40 CFR 70.8.

(5) No appeal concerning an Acid Rain requirement shall result in a stay of any provision of the Acid Rain permit except as provided in § 72.95.

(j) *Cooperation with State utility rate regulator.* In considering any permit application and compliance plan under this part, the permitting authority shall ensure coordination with the applicable electric utility rate regulator, in the case of regulated utilities, and with unregulated public utilities.

(k) *State permit program evaluation.* The permitting authority shall periodically evaluate the extent to which its Acid Rain permitting program meets the Acid Rain requirements and supports a cost-effective implementation of the program. The permit fee rates set by the permitting authority must be adequate to cover such evaluation.

§ 72.203 Submission by affected sources of permit applications and compliance plans for phase II.

(a) Complete Phase II permit applications and proposed compliance plans that are timely received under this subpart shall be binding on the designated representative of the affected unit, and shall be enforceable as a permit for purposes of 40 CFR parts 70–78 and titles IV and V of the Act until

the permitting authority issues a permit for the affected source.

(b) Sulfur Dioxide Applications and Compliance Plans. The designated representative of any existing Phase II affected unit shall submit a complete sulfur dioxide permit application and proposed compliance plan for that unit to the permitting authority, and to the Administrator not later than January 1, 1996.

(c) New units. For any new affected unit as specified in § 72.7 a complete Acid Rain permit application shall be submitted not later than 24 months before the later of:

(1) January 1, 2000; or

(2) The date on which the unit commences commercial operation.

(d) Nitrogen Oxides Applications and Compliance Plans. The designated representative of any Phase II affected unit subject to an emissions limitation requirement for nitrogen oxides under section 407 of the Act and 40 CFR part 76, shall submit a complete permit application and proposed compliance plan for such unit to the permitting authority and to the Administrator, not later than January 1, 1998 or for new units, not later than 24 months before the date on which the unit commences operation. The permitting authority shall issue a permit to the affected source that satisfies the requirements of Title V and this title, including any appropriate monitoring and reporting requirements.

§ 72.204 State issuance of phase II permits.

(a) *State permit issuance.* (1) States with operating permit programs pursuant to 40 CFR part 70 and this part that have been approved by the Administrator on or before July 1, 1996, shall be responsible for issuing Phase II permits to all Phase II affected units in that State.

(2) States that have obtained interim operating permit program approval (as defined in 40 CFR 70.4(d)) on or before July 1, 1996, shall issue permits in accordance with the requirements of this part, and 40 CFR part 70 and 40 CFR parts 73–78 to all Phase II affected units in that State.

(3) States that have obtained partial operating permit program approval (as defined in 40 CFR 70.4(c)) on or before July 1, 1996, shall issue permits in accordance with the requirements of this part and 40 CFR part 70 and 40 CFR parts 73–78 to all Phase II affected units that are required to obtain a permit as a result of the partial approval.

(4) Permit Issuance. The permitting authority shall follow all applicable permit issuance procedures specified in 40 CFR part 70 and of this subpart.

(5) Permit Content. (i) The Acid Rain portion of the permit issued to the source under 40 CFR part 70 shall contain all the applicable requirements specified in subpart E, including the standard Acid Rain permit provisions specified in § 72.54.

(ii) Each permit shall specify the basic and bonus allowance allocations for each affected unit at the source as specified in 40 CFR part 73.

(b) *Permit issuance deadline.* (1)(i) States with approved operating permits programs shall issue operating permits that include sulfur dioxide requirements, on or before December 31, 1997, that satisfy the requirements of this part, 40 CFR part 70 and 73–78, to Phase II affected sources, provided that the designated representative for the affected source submitted a timely and complete permit application pursuant to subpart C. Failure of the State to issue such permit by the deadline stated shall be subject to administrative review. No Acid Rain permit shall be issued by default, notwithstanding State law to the contrary.

(ii) The Acid Rain portion of permits, issued pursuant to this section, including permit renewals, shall have terms of 5 years and shall become effective no later than January 1, 2000. Prior to the effective date of the Acid Rain portion of the operating permit, the affected source shall be bound by the terms of the complete approved permit application, and by the proposed approved compliance plan except as modified by the permitting authority when issuing the permit.

(2) Nitrogen Oxides. (i) Not later than January 1, 1998, the designated representative of an affected source shall submit a complete and timely Acid Rain nitrogen oxides permit application and proposed compliance plan, in accordance with subpart C. (The first Phase II Acid Rain permit applications due January 1996 are not required to address nitrogen oxides limitations.)

(ii) Not later than July 1, 1999, the permitting authority shall reopen the Acid Rain portion of the operating permit issued in accordance with paragraph (b)(1) of this section to add the Acid Rain nitrogen oxides requirements pursuant to this part and 40 CFR parts 73–78.

(iii) The reopening of a permit for the purpose of adding the Acid Rain nitrogen oxides requirements shall not affect the term of the permit, which shall continue to be effective for 5 years.

§ 72.205 Federal issuance of phase II permits.

(a) The Administrator shall issue Phase II permits pursuant to 40 CFR parts 71–78 to any affected units located in a State that does not have an operating permit program approved by the Administrator pursuant to titles IV and V of the Act, to 40 CFR part 70, and to subpart I of this part on or before July 1, 1996, including interim or partial approvals. (This requirement shall in no way be construed as prohibiting the Administrator from approving 40 CFR part 70 State operating permit programs after July 1, 1996.) The Administrator shall cease issuing Phase II permits in any State upon approval of the State program in accordance with this part and 40 CFR part 70. Upon approval of such program the State shall be responsible for Acid Rain permitting in accordance with § 72.204.

(b) Permit Issuance Deadline. (1)(i) On or before January 1, 1998, the Administrator shall issue a Phase II permit governing sulfur dioxide requirements pursuant to this part, 40 CFR part 71, and 40 CFR parts 73–78, to each affected source located in a State which, on July 1, 1996, did not have an approved program under 40 CFR part 70; *Provided* that the designated representative for the affected source submitted a timely and complete Acid Rain permit application to the Administrator pursuant to subpart C. A failure by the Administrator to issue a Phase II permit in accordance with this paragraph shall be grounds for the filing of an appeal as provided in subpart H.

(ii) Notwithstanding paragraph (b)(1)(i) of this section the Administrator may delegate to any State that obtains operating permit program approval after July 1, 1996, the responsibility for permit review and implementation.

(iii) Each Phase II permit issued by the Administrator pursuant to this section shall have a term of 5 years. Prior to the effective date of the Acid Rain portion of the permit, the affected source shall be bound by the terms of the complete permit application and approved compliance plan as modified or conditioned by the Administrator when issuing the permit.

(2) Nitrogen Oxides. (i) Phase II Acid Rain permits issued by the Administrator pursuant to paragraph (b)(1) of this section may, but are not required to, include Acid Rain nitrogen oxides requirements.

(ii) Notwithstanding paragraph (b)(2)(i) of this section, not later than 6 months following submission by the designated representative of an affected unit of a complete and timely Acid Rain nitrogen oxides permit application and proposed compliance plan in accordance with subpart C, the Administrator shall reopen the Acid

Rain portion of the permit issued pursuant to paragraph (b)(1)(i) of this section to add the Acid Rain nitrogen oxides requirements pursuant to this part, 40 CFR part 71, and 40 CFR parts 75–78.

(iii) The reopening of a permit for the purposes of adding the Acid Rain nitrogen oxides requirements shall not alter or affect the term of the permit, which shall continue to be effective for a term of 5 years.

(c) *Permit issuance.* In taking permit action under this section, the Administrator shall issue Phase II permits in accordance with subpart G of this part and 40 CFR part 71.

(d) *Permit content.* (1) Permits issued under this section shall contain all applicable requirements specified in subpart E, including the standard Acid Rain permit provisions specified in § 72.54.

(2) Permits issued under this section shall specify the basic allowance allocation for the unit specified in 40 CFR part 73.

Subpart J—Permit Revisions

§ 72.300 General.

(a) This subpart shall govern revisions to any Federally issued Acid Rain permit, and to the Acid Rain portion of any operating permit issued by a State with an approved permit program pursuant to 40 CFR part 70.

(b) The provisions of this subpart, including the procedures applicable to automatic amendments, administrative amendments, fast-track modifications, and permit modifications, shall supersede the operating permit revision procedures specified in 40 CFR part 70 with regard to revision of any Acid Rain program permit provision.

(c) No permit revision shall excuse any violation of an Acid Rain program requirement that occurred prior to the effective date of the revision.

(d) The terms of the Acid Rain permit shall apply while the permit revision is pending.

(e) Notice of any determination by a State interpreting, modifying, or voiding any Acid Rain permit provision shall, by operation of law, constitute a permit modification and shall be subject to review by the Administrator pursuant to 40 CFR 70.8.

(f) The standard provisions of § 72.54, including the requirement for a unit to hold allowances in its Allowance Tracking System compliance subaccount as of the allowance transfer deadline not less than the unit's sulfur dioxide emissions for the calendar year, are not revisable.

§ 72.301 Permit modifications.

(a) Acid Rain permit revisions that shall follow the permit modification procedures include but are not limited to:

(1) Relaxation of a monitoring requirement;

(2) Relaxation of an excess emission offset requirement after approval of the excess emission offset plan by the Administrator;

(3) Incorporation of a new method of compliance that the source did not submit for approval and comment during the permit issuance or renewal process; unless such revision is made using the fast-track modification process; except that incorporation of a new reduced utilization plan that the source did not submit for approval and comment during the public comment period shall not be considered a modification unless the plan designates a compensating unit;

(4) Incorporation of a final nitrogen oxides alternative emissions limitation following a demonstration period;

(5) A change in an existing compliance option that results in a previously unaffected unit becoming affected under the Acid Rain program;

(6) Changes to a Phase I extension plan, repowering plan, nitrogen oxides averaging plan, nitrogen oxides alternative emissions plan, or nitrogen oxides compliance deadline extension plan; and

(7) A determination by a State interpreting, modifying or voiding any Acid Rain permit provision.

(b) Modifications of Acid Rain permits shall follow the procedures set forth at 40 CFR 70.7(d).

§ 72.302 Fast-track modifications.

Option 1

(a)(1) Upon the consent of the permittee, the permitting authority may modify a permit using the procedures of this section to incorporate a new optional method of compliance (except that incorporation of a new reduced utilization plan that does not name a compensating unit may be done using the administrative permit amendment procedure pursuant to § 72.303 in lieu of this procedure) without following the permit modification procedures set forth in § 72.301. This procedure may also be used for a change in an existing compliance option that results in a previously unaffected unit becoming affected under the Acid Rain program, or for changes to a Phase I extension plan, repowering plan, nitrogen oxides averaging plan, nitrogen oxides alternative emissions plan, or nitrogen oxides compliance deadline extension plan.

(2) In lieu of this procedure, the permit modification procedure may be used to effect these changes. The administrative amendment procedure pursuant to § 72.303 and the minor permit amendment procedure pursuant to 40 CFR part 70 shall not be used for the permit revisions listed in paragraph (a)(1) of this section.

(b) Procedure. The following procedures shall apply to all fast-track modifications.

(1) The designated representative shall submit to the permitting authority a complete compliance plan form for the new optional method of compliance that the designated representative proposes to use.

(2) The permitting authority shall approve or disapprove the application within 30 days following receipt of a complete compliance plan. Disapproval of the compliance plan shall be considered a permitting decision for purposes of administrative review.

(3) If the permitting authority proposes to approve the new method of compliance, notification of the proposed modification shall be sent to all persons who commented during the public comment period on the permit for the source proposed to be modified. For substitution plans and nitrogen oxides emissions averaging plans, notice shall also be published in a newspaper of general circulation in the area affected by the source or unit proposed to be newly affected under the substitution or averaging plan.

(4) Persons who receive notice have 15 days in which to object to the proposed modification.

(5) If no significant objections are received, the proposed modification shall take effect at the end of the 15-day comment period.

(6) If significant objections to the proposed modification are received within 15 days, the proposed modification shall follow the standard permit modification procedures set forth in § 72.301.

Option 2

(a)(1) Upon the consent of the permittee, the permitting authority may modify a permit to incorporate a new optional method of compliance (except that incorporation of a new reduced utilization plan that does not name a compensating unit may use the administrative amendment procedure pursuant to § 72.303 in lieu of this procedure) without following the permit modification procedures set forth in § 72.301. This procedure may also be used for a change in an existing compliance option that results in a

previously unaffected unit becoming affected under the Acid Rain program, or for a change to a Phase I extension, repowering, nitrogen oxides averaging, nitrogen oxides alternative emissions, or nitrogen oxides compliance deadline extension plan.

(2) In lieu of this procedure, the permit modification procedure may be used to effect these changes. The administrative amendment procedure pursuant to § 72.303 and the minor permit amendment procedure pursuant to 40 CFR part 70 shall not be used for the permit revisions listed in paragraph (a)(1) of this section.

(b) Procedure. The following procedures shall apply to all fast-track modifications.

(1) The designated representative shall complete a compliance plan form for the new optional method of compliance that the designated representative proposes to use.

(2) The designated representative shall give notice to the Administrator, the State, and public notice of the proposed fast-track modification through publication in a journal or newspaper of national and general circulation. The designated representative shall also send individual notice to each interested person (as that term is defined in 40 CFR part 70) who commented during the public comment period on the permit proposed to be modified.

(3) The public shall have a period of 30 days, commencing on the date of publication of the notice, to comment on the proposed modification. Comments shall be submitted in writing and sent to the permitting authority and to the source.

(4) The designated representative shall submit to the permitting authority the proposed modification, on or before commencement of the public comment period.

(5) The permitting authority shall consider the application and the comments received, and approve or disapprove the proposed modification within 30 days of receipt of a complete application and comments. An approved modification shall be effective immediately upon approval. Approval or disapproval of the proposed modification shall be considered a permitting decision for purposes of administrative review.

§ 72.303 Administrative permit amendment.

(a) Acid Rain permit revisions that use the administrative permit amendment procedures shall include, but are not limited to:

(1) Activation of a compliance plan option approved in the initial permit decision, provided the option is activated within the time specified by the permit pursuant to this part;

(2) Change in the designated representative, provided that a new certificate of representation is submitted;

(3) Correction of typographical errors;

(4) Increases in monitoring frequency;

(5) Changes in names, addresses or phone numbers;

(6) Changes in ownership or operation control, provided that a new certificate of representation is submitted within 30 days;

(7) Inclusion of an excess emissions offset plan that has been approved by the Administrator pursuant to 40 CFR part 77.

(8) Incorporation of a reduced utilization plan that does not name or change requirements applicable to a compensating unit, provided that such plan meets all applicable requirements of § 72.43;

(9) Termination of a compliance option in the permit that does not involve de-designating a unit; except that this procedure shall not be used for termination of a Phase I extension plan; nor shall it be used to terminate a repowering plan after December 31, 1999;

(10) Changes in a substitution or reduced utilization plan that do not result in a previously unaffected unit becoming affected under the Acid Rain program; and

(11) De-designation of a substitution unit or compensating unit, provided that the unit complies with the requirements of § 72.41(c)(2) for substitution units, and § 72.43(b)(2) for compensating units.

(b) Administrative amendments of Acid Rain permits shall follow the procedures set forth at 40 CFR 70.7(e).

(c) Actual notice of administrative amendments to Acid Rain permits shall be given to all interested persons by the source. A certification that such notice was given shall be submitted to the permitting authority by the designated representative for the source.

§ 72.304 Automatic permit amendment.

Pursuant to 40 CFR part 73, all allowance allocations to, acquisitions for, and transfers to or from, an affected unit's Allowance Tracking System account shall, upon recordation by the Administrator, be deemed to automatically amend and become a part of the affected unit's permit by operation of law without any further permit review or revision. Such allocations and transfers shall be governed by 40 CFR part 73.

§ 72.305 Excess emissions offset plans.

(a) Any excess emissions offset plan approved by the Administrator pursuant to the requirements of 40 CFR part 77, shall be deemed to be incorporated into and to revise the permit upon approval by the Administrator. The Administrator shall approve excess emissions offset plans in accordance with the requirements of 40 CFR part 77. The incorporation of the approved excess emissions offset plans into the permit shall be subject to the requirements of this subpart applicable to administrative permit amendment.

(b) Any requirements in the approved excess emissions offset plan that contradict requirements of the permit shall be deemed to supersede the inconsistent permit requirements.

(c) The excess emissions offset plan approved pursuant to 40 CFR part 77 shall be appended to the permit and shall be made available to the public upon request.

§ 72.306 Permit reopenings.

(a) As provided in 40 CFR 70.7(g), the permitting authority shall reopen a permit for cause, including whenever additional requirements become applicable to an affected source.

(b) Consistent with subpart I, and with 40 CFR parts 73–78, following submission of a complete nitrogen oxides application and proposed compliance plan, the permitting authority shall reopen the permit within 6 months to incorporate applicable nitrogen oxides requirements.

(c) A permit reopening shall trigger all the procedural requirements of subpart G or subpart I and 40 CFR part 70 pertaining to the issuance of permits.

(d) Any reopening of the permit shall not affect the term of the Acid Rain permit, which shall continue to be 5 years.

Subpart K—Compliance Certification

§ 72.400 General.

(a) The designated representative for each affected unit shall submit all Acid Rain compliance certifications required by 40 CFR parts 72–78 to the Administrator and the permitting authority and in accordance with this section.

(b) The permitting authority shall not accept an Acid Rain compliance certification unless submitted by a designated representative duly certified to represent the affected unit pursuant to subpart B of this part.

(c) For purposes of the annual compliance certification, to hold allowances in the compliance year

subaccount for the unit shall be deemed to mean that the allowances are recorded or for which a transfer request has been properly submitted in accordance with the procedures specified in 40 CFR part 73.

§ 72.401 Quarterly reports.

(a) The designated representative of each affected unit shall submit the following compliance certifications for the unit on a quarterly basis:

(1) Certified emissions data and quality assurance information as required by 40 CFR part 75.

(2) Certification of the unit's compliance status with regard to any scheduled deadline or increment of progress specified in the permit occurring during the prior calendar quarter.

(b) Quarterly monitoring reports for the first three calendar quarters of each year shall be postmarked not later than 30 days following the last day of each calendar quarter (April 30, July 30, October 30). The quarterly report for the fourth calendar quarter of each year, shall be submitted concurrently with the unit's annual report.

§ 72.402 Annual reports.

The designated representative of each affected unit shall submit the following compliance certifications for the unit annually, not later than the allowance transfer deadline established pursuant to 40 CFR part 73:

(a) A general certification, using SF# 72402 in Appendix C of this part, as follows:

(1) Identification of the affected unit;

(2) The compliance plan option(s) that apply to this unit; and

(3) Designated representative identification.

(b) Certification of the unit's compliance status with regard to whether the annual sulfur dioxide emissions from the affected unit did or did not exceed the allowances held as of the allowance transfer deadline in the unit's Allowance Tracking System compliance subaccount. The certification shall include the following information:

(1) The total tons of sulfur dioxide emitted for the calendar year by the affected unit;

(2) The number of allowances held as of the allowance transfer deadline in the affected unit's compliance subaccount; and

(3) The baseline and actual annual heat input (in mmBtu) and generation (in Kwh) for the calendar year for the affected unit.

(c) If the affected unit's actual heat input, reported in accordance with paragraph (b)(3) of this section, is less than the unit's baseline the designated representative shall include in the annual report one or more of the following demonstrations for the unit:

(1) That the utilization below baseline was due in whole or in part to either:

(i) Dispatching between Phase I units in the unit's utility system, and is accounted for by net aggregate utilization of Phase I affected units in the utility system of which the unit is a part above the utility system's Phase I units' aggregate baseline, in accordance with the demonstration specified in § 72.409(c); or

(ii) A calendar year sales decrease for the utility system of which the unit is a part, in accordance with the demonstration specified in § 72.409(b).

(2) Verification in accordance with the unit's permit and approved reduced utilization plan pursuant to § 72.43, using SF# 7243A in appendix C of this part, that:

(i) The reduced utilization was due in whole or in part to energy conservation, as provided in the approved reduced utilization plan; or

(ii) The reduced utilization was due in whole or in part to improved unit efficiency, as provided in the approved reduced utilization plan; or

(iii) The reduced utilization was due in whole or in part to compensating generation supplied by one or more sulfur-free generators or designated compensating unit, as provided in the approved reduced utilization plan.

(3) If none of the conditions in paragraph (c) (1) or (2) of this section can be demonstrated, for all or any part of the under-utilization below baseline the designated representative for the unit to which the compliance certification applies shall certify the extent to which any under-utilization at the unit reported in paragraph (b)(3) of this section was due to dispatching within the unit's NERC region or utility system to non-Phase I affected units and generators, not including those identified in paragraph (c)(2)(iii) of this section, as identified in the permit application and permit for the source in accordance with subpart C of this part. To the extent that under-utilization was due to such dispatching, allowances shall be deducted from the unit's Allowance Tracking System account in accordance with § 72.409(e).

(4) If the utilization below baseline was caused by a forced outage as documented in the attached SF# 72409A in appendix C of this part, one or more of the demonstrations in paragraph (c) (1) through (3) of this section must be made to account for the reductions. In addition, if such forced outage is permanent or prolonged the unit must meet the requirements of § 72.409(d)(2).

(5) The designated representative of each unit shall certify, in accordance with § 72.43, whether the allowances held in the unit's compliance subaccount as of the allowance transfer deadline equal or exceed the emissions in tons per year that would have occurred but for the under-utilization not accounted for by paragraphs (c) (1) through (4) of this section.

(d) Certification of the unit's compliance status, in accordance with 40 CFR part 76, using SF# 72402 in appendix C of this part, regarding whether the emissions of nitrogen oxides for the calendar year did or did not exceed the applicable Acid Rain program nitrogen oxides emissions limitation in accordance with 40 CFR part 76. The certification shall contain the information required by 40 CFR part 76, including:

(1) The applicable emissions limitation for the unit;

(2) The total tons of emissions for the year; and

(3) The extent of any exceedance.

§ 72.403 Other.

The designated representative of each affected unit shall submit the following compliance certifications to the Administrator and the permitting authority for the unit:

(a) Notice 60 days prior to any proposed revision in a scheduled increment of progress specified in the permit, including:

(1) A change in the date for taking a unit out of operation to repower under § 72.44(e)(1)(iv).

(2) A change in any scheduled date leading to and including the start-up of a new unit as specified in § 72.45(d)(2).

(3) A change in any scheduled date in the installation and start-up schedule for 90% control technology at a Phase I Extension unit as specified in § 72.42(e)(2)(i)(B)(*4*).

(4) A change in the date for the start-up performance test for the qualifying Phase I technology as specified in § 72.42(e)(2)(i)(D)(*1*).

(5) A change in the date for an annual performance test for the qualifying Phase I technology as specified in § 72.42(e)(2)(i)(D)(*2*), and

(6) A change in the scheduled increment of progress in an excess emissions offset plan pursuant to 40 CFR 77.2(e)(5)(vii).

(b) Notice 10 days after any deviation from any applicable compliance plan requirement, including:

(1) Failure to meet any of the dates scheduled or revised pursuant to paragraph (a) of this section,

(2) Failure to make the required submission under a repowering plan by the deadline specified in § 72.44(e)(1)(v),

(3) Failure to submit an application for a final nitrogen oxides alternative emissions limitation by the deadline specified in § 72.47(d)(2).

(c) Notice within 10 days following any nonscheduled event that affects the sources ability to comply with any applicable requirement of this part and 40 CFR parts 73–78, including:

(1) A forced outage,

(2) A sudden unavailability of the designated representative (including any alternate designated representative).

§ 72.404 Certification statement.

(a) All compliance certifications required by this part shall include the certification of truth and accuracy by the designated representative specified in § 72.9(a)(2).

(b) Compliance certifications shall include all other information required by the Administrator in accordance with this part.

§ 72.405 Compliance option certifications.

The designated representative of each affected unit shall also submit in the annual, quarterly, and other reports the compliance certifications required by the sections referenced below:

(a) Phase I Extensions Plans pursuant to § 72.42, including § 72.42(e)(2)(D)(*1*) Post Combustion Control Technology Start-up Performance Testing, § 72.42(e)(2)(D)(*2*) Post Combustion Control Technology Annual Demonstration, § 72.42(e)(2)(D)(*3*) Combustion Technology Testing, § 72.42(e)(2)(D)(*4*) Additional Tests.

(b) Phase I Reduced Utilization Plans pursuant to § 72.43, including § 72.43(b)(3)(v) Verification of Energy Conservation Baseline—Effective Date, § 72.43(b)(4)(v) Verification of Improved Unit Efficiency Baseline—Effective Date, § 72.43(b)(6) Annual Verification for Energy Conservation, Improved Unit Efficiency and Compensating Unit/ Sulfur-Free Generation.

(c) Phase II Repowering Extensions pursuant to § 72.44, including § 72.44(e)(1)(v) Technology Demonstration, § 72.44(e)(1)(vii) Special Emissions Report.

(d) New Unit Plans pursuant to § 72.45.

(e) Nitrogen Oxides Emissions Averaging Plans pursuant to § 72.46 and 40 CFR part 76.

(f) Nitrogen Oxides Alternative Emissions Limitations Plans pursuant to § 72.47 and 40 CFR part 76.

(g) Nitrogen Oxides Compliance Deadline Extension Plans pursuant to § 72.48 and 40 CFR part 76.

(h) Opt-in Plans pursuant to 40 CFR part 74.

(i) Common-Stack Plans pursuant to § 72.50.

(j) Excess Emissions pursuant to 40 CFR part 77, including 40 CFR 77.2(e)(7) Submission of Progress Reports.

§ 72.406 Demonstration of compliance with substantive requirements of compliance plans.

Each compliance certification required by § 72.405 shall include the demonstrations required to be made by the applicable compliance option.

§ 72.407 Submission of documents.

All compliance certifications shall be submitted to the Administrator and the permitting authority as provided in Subpart A of this part.

§ 72.408 Excess emissions.

Submissions required by 40 CFR part 77 for units with excess emissions in any calendar year shall be certified in accordance with this subpart and 40 CFR part 77.

§ 72.409 Accounting for phase I shifts in utilization.

(a) Compliance Certification Reporting. In accordance with § 72.402(b)(4)(ii), the designated representative for any Phase I affected unit with under-utilization not accounted for by a reduced utilization compliance plan approved pursuant to § 72.43 shall submit one or more of the following with the unit's annual report:

(1) A demonstration that the under-utilization at the Phase I affected unit below its baseline was due, in whole or in part, to shifts of generation to other Phase I affected units in the same system, calculated as provided in paragraph (b) of this section;

(2) A demonstration that the under-utilization at the affected unit was due, in whole or in part, to a system-wide decrease in electrical demand, calculated as provided in paragraph (c) of this section;

(3) A demonstration that the under-utilization at the Phase I affected unit was below its baseline due in whole or in part to a forced outage, as provided in paragraph (d) of this section; or

(4) The submission required by paragraph (e) of this section.

(b) To demonstrate that the unplanned under-utilization at the affected unit below its baseline was due, in whole or in part, to shifts of generation from the unit to other Phase I affected units, the unit shall use the following calculation:

(1) Calculate the aggregate utilization (in mmBtu and Kwh) of all Phase I affected units within the utility system identified in the permit application in accordance with § 72.31(a)(5);

(2) Compare the calculation of paragraph (b)(1) of this section, to the aggregate baseline of all Phase I affected units within the system;

(3) If paragraph (b)(1) of this section is greater than or equal to the aggregate baseline of all affected units within a system, calculated pursuant to paragraph (b)(2) of this section, no further demonstration is necessary. If not go on to the next demonstration.

(c) To demonstrate that unplanned under-utilization at a Phase I affected unit below its baseline was due, in whole or in part, to a system-wide decrease in sales, the unit shall use the following calculation:

(1) Calculate the percentage decline of aggregate annual kilowatt hour sales for the utility system, as identified in the permit application in accordance with § 72.31(a)(5), compared to system sales during the preceding calendar year;

(2) Calculate the decline in utilization of the Phase I unit (in mmBtu, Kwh, and percentage) as compared to baseline;

(3) If paragraph (c)(1) of this section is greater than or equal to the actual reduced utilization at the Phase I unit, calculated pursuant to paragraph (c)(2) of this section, no further demonstration is necessary. If not go on to the next demonstration.

(d) Forced Outages. (1) In addition to the other requirements in this section, where a forced outage has led to unplanned reduced utilization at a Phase I affected unit, the designated representative shall provide the Administrator with the following information, using SF# 72409A in appendix C of this part:

(i) The name of the unit where the forced outage occurred;

(ii) The event(s) causing the forced outage;

(iii) The extent of under-utilization attributable to the forced outage (in mmBtu and Kwh);

(iv) The duration or expected duration of the forced outage and, if the unit has not been returned to normal service, the expected date the unit will be returned to normal service; and

(v) A demonstration of the measures taken by the owners and operators to restore the unit to normal service as expeditiously as practicable, including information on measures taken to prevent any similar forced outage in the future;

(2) If the designated representative anticipates that the forced outage will

continue in the following calendar year and/or that the forced outage will cause the unit to permanently transfer generation to one or more units that are not otherwise affected during Phase I, the designated representative shall:

(i) Amend the compliance plan for the unit by submitting a reduced utilization plan pursuant to § 72.43 designating one or more compensating units; or

(ii) Demonstrate through an independent auditor or utility rate regulatory authority determination, or other documentation, that it is not possible to restore the unit to service at a reasonable cost.

(e) To the extent the demonstrations required by paragraphs (a)(1)–(3), of this section, do not account for the entire amount of unplanned under-utilization below baseline at the Phase I affected unit for a calendar year, allowances shall be deducted from the unit's Allowance Tracking System compliance subaccount for the year to account for increased emissions at the unaffected units providing compensating generation using the formulas specified in paragraphs (e) (1) and (2) of this section. The designated representative for the unit experiencing the under- utilization shall submit, not later than midnight, January 30, of the year following such under-utilization, a report, using SF# 72409 in appendix C of this part, calculated as follows:

(1) One allowance shall be surrendered for each ton of sulfur dioxide, calculated using the following formula:

$$\{(A-E)-[(A-E)\times F]\times(C\div B)\}\times D\div 2000$$

where:

A is the net aggregate under-utilization at all Phase I units in the utility system below the aggregate baseline for all affected units in the utility system (in mmBtu), calculated by subtracting the gross under-utilization not accounted for under an approved reduced utilization plan (B) from the aggregate utilization above baseline (in mmBtu) of all Phase I units in the system operated above baseline;

B is the utility system gross under-utilization not accounted for under an approved reduced utilization plan (in mmBtu), calculated by adding the aggregate utilization below baseline not accounted for under an approved reduced utilization plan for all affected units within the system;

C is the utilization below baseline for the individual affected unit for which the calculation is being made (in mmBtu);

D is the Btu-weighted average annual emissions rate for the previous calendar year for (1) all units in the NERC region where the under-utilized unit is located, (2) for all units within the utility system and units outside of the utility system that have been specifically identified, or (3) a combination of (1) and (2), calculated in accordance with paragraph (2), below;

E is the aggregate under-utilization at all Phase I units in the utility system below their aggregate baseline that is attributable to the system-wide percentage decline in utilization, as calculated pursuant to § 72.409(b)(1); and

F is the percentage of the total annual Btu's above baseline that is attributable to Phase I units outside of the utility system located in the NERC region where the unit that experienced the under-utilization is located, multiplied by the percentage of the utility's generation for which the NERC region average emissions rate will be used in paragraph (2), below (i.e., 100% in paragraph (e)(2)(ii) and a in paragraph (e)(2)(iii)).

(2) *Formula for Calculating Average Emissions Rate.* The Btu-weighted average annual emissions rate for the previous year (D in paragraph (e)(1), of this section) according to one of the following options:

(i) Based on the weighted-average emissions rate of all units within the NERC region where the unit that experienced under-utilization is located, as set forth below:

$$D = \frac{\sum_{i=1}^{n} (c_i \times d_i)}{\sum_{i=1}^{n} c_i}$$

where:

c_i is the difference between the annual heat input for each unit within the NERC region (in mmBtu) and the baseline for each unit within the NERC region (in mmBtu).

d_i is the average annual emissions rate for each unit within the NERC region (in lbs/mmBtu).

n is the number of units in the NERC region.

(ii) If all of a utility's compensating generation can be accounted for by generation from the utility system and specific units outside of the system, based on the weighted-average emissions rate of all units within the utility system and units outside of the utility system that have been specifically identified, as set forth below:

$$D = \frac{\sum_{i=1}^{n} (e_i \times f_i)}{\sum_{i=1}^{n} e_i}$$

where:

e_i is the difference between the annual heat input for each unit within the utility system and each specifically identified unit outside of the utility system (in mmBtu) and the baseline for each unit within the utility system and each specifically identified unit outside of the utility system (in mmBtu).

f_i is the average annual emissions rate for each unit within the utility system and each specifically identified unit outside of the utility system.

n is the number of units within the utility system and specifically identified units outside the utility system providing compensating generation.

(iii) If only a percentage of a utility's compensating generation can be accounted for by generation from the utility system and specific units outside of the system, based on a combination of (1) the weighted-average emissions rate of all units within the NERC region where the unit that experienced under-utilization is located and (2) the weighted-average emissions rate of all units within the utility system and units outside of the utility system that have been specifically identified, as set forth below:

$$D = a \times \frac{\sum_{i=1}^{n} (c_i \times d_i)}{\sum_{i=1}^{n} c_i} + b \times \frac{\sum_{i=1}^{m} (e_i \times f_i)}{\sum_{i=1}^{m} e_i}$$

where:

a is the % of compensating generation from units outside of the utility system that have not been specifically identified, for which the NERC region average emissions rate will be used.

b is the % of compensating generation from (1) units within the utility system and (2) units outside the utility system that have been specifically identified.

c_i is the difference between the annual heat input for each unit within the NERC region (in mmBtu) and the baseline for each unit within the NERC region (in mmBtu).

d_i is the average annual emissions rate for each unit within the NERC region (in lbs/mmBtu).

e_i is the difference between the annual heat input for each unit within the utility

system and each specifically identified unit outside of the utility system (in mmBtu) and the baseline for each unit within the utility system and each specifically identified unit outside of the utility system (in mmBtu).

f_i is the average annual emissions rate for each unit within the utility system and each specifically identified unit outside of the utility system.

n is the number of units in the NERC region.

m is the number of units within the utility system and specifically identified units outside the utility system providing compensating generation.

(f) Action of Administrator. Where a shift in generation from an affected unit to a non-affected unit has resulted in unplanned under-utilization at a Phase I affected unit as provided in this section, the Administrator shall deduct allowances from the compliance subaccount according to the formulas in paragraph (e) of this section and 40 CFR 73.35.

Subpart L—Phase I Extension Early Ranking Procedures

§ 72.500 General.

(a) Applicability. This subpart shall apply:

(1) To any existing appendix A affected unit, and to the designated representative, owners, and operators of any such unit, seeking an early ranking of a proposed Phase I Extension plan for the unit, as provided for in § 72.42, for a 2-year extension of the deadline for meeting the Acid Rain Program Phase I sulfur dioxide emissions reduction requirements of this part; and

(2) To any other affected unit listed in appendices A or B of this part, and to the designated representative, owners, and operators of any such unit, that is designated as a control unit in a proposed Phase I Extension plan submitted under § 72.42 and in an Early Ranking application under § 72.501, below.

(b) The Administrator's initial action on an Early Ranking application submitted under this subpart shall be a conditional determination of the proposed Phase I Extension plan's order of receipt and Phase I Extension allowance award only, and shall be subject to:

(1) The Administrator's action on a timely and complete permit application submitted pursuant to subpart C of this part by the designated representative(s) for the source(s) where the affected unit(s) covered by the proposed Phase I Extension plan and Early Ranking application is (are) located;

(2) The Administrator's thorough review of the complete proposed Phase I Extension plan submitted with the permit application pursuant to § 72.42 and subpart C of this part;

(3) As deemed necessary by the Administrator, to timely modification of the proposed Phase I Extension plan; and

(4) Compliance by each unit governed by the proposed Phase I Extension plan and Early Ranking application with the 90% control requirements specified in § 72.42.

§ 72.501 Early ranking procedure.

The order of receipt of a proposed Phase I Extension plan, as provided for in § 72.42(c), shall be determined on a conditional basis prior to submission of a complete permit application, as required by subpart C of this part, pursuant to the following procedure:

(a) Designated Representative Personal Identification Number. In order to implement the Early Ranking procedure of this subpart, the designated representative for each affected unit seeking to apply for a Phase I Extension under § 72.42 shall submit to the Administrator a certificate of representation in accordance with subpart B of this part, using SF# 7220 and SF# 7220A in appendix C of this part.

(b) The Administrator will issue to any person submitting a certificate of representation pursuant to subpart B and paragraph (a), of this section, a secure DR PIN # within 30 days of receipt of the certificate of representation, and shall provide the designated representative notice of the procedures to be followed for participation in the phone queuing, and of follow-up procedures for the processing of Phase I Extension Early Ranking applications, as provided in paragraphs (c) and (d), of this section.

(c) Phone Queuing Procedure. (1) Beginning not earlier than 8 a.m. EST on the date specified in the notice issued under paragraph (b) of this section, the designated representative for any unit electing to participate in the Phase I Extension Early Ranking procedure of this subpart shall call the telephone number obtained by the applicant by following the procedures specified in the notice issued under paragraph (b) of this section.

(2) Upon being connected to the Early Ranking voice-mail system and upon receiving recorded instructions, the designated representative shall enter a secure application identification number, registered through the procedures specified in the notice issued under paragraph (b) of this section, and the DR PIN # obtained in the notice issued under paragraph (b) of this section.

(3) As instructed by the Early Ranking voice-mail system the designated representative shall, thereafter, register by voice mail the unit or units applying for the Phase I Extension Early Ranking.

(d) Written Phase I Extension Early Ranking Application. (1) Not later than midnight of the same business day an Early Ranking application is registered pursuant to the phone queuing procedure in paragraph (c) of this section, the designated representative shall submit a complete written Phase I Extension Early Ranking application to the Administrator, in accordance with paragraphs (d)(2)–(4), of this section. This written submission, if timely made, shall perfect the Early Ranking application's order of receipt.

(2) Contents of Phase I Extension Ranking Application. The designated representative for each affected unit seeking a Phase I Extension under § 72.42 who participated in the phone queuing procedure of paragraph (c) of this section, shall submit to the Administrator a complete Phase I Extension Ranking Application by the deadline specified in paragraph (d)(1) of this section, using SF# 7242 in appendix C of this part. The ranking application shall contain all of the information required in § 72.42(e)(1), (e)(2)(i), (e)(2)(ii)(A)(*1*) and (e)(2)(ii)(B), as well as the provisions of § 72.500(b).

(3) Phase I Extension Early Ranking Applications shall be submitted by certified mail to the following address: Chief, Permits and Technologies Section, U.S. Environmental Protection Agency, OAR/OAIAP/Acid Rain Division (ANR-445), 401 M. Street SW., Washington, DC 20460.

(4) The submissions made pursuant to this subsection shall be conditional upon compliance with the requirements of this subpart and § 72.42 of this part.

(e) Administrator's Review and Action on Early Ranking Applications. For each Early Ranking application submitted in accordance with paragraph (d) of this section, the Administrator will notify the designated representative of the unit(s) governed by the application, within 30 days of receipt of the application by EPA, of the following information:

(1) The date the Early Ranking application submitted pursuant to paragraph (d) of this section was received by EPA;

(2) Whether the Early Ranking application submitted pursuant to paragraph (d) of this section is complete;

(3) Based on the ranking of the application submitted pursuant to

paragraph (d) of this section, as established by the phone queuing procedure of paragraph (c) of this section, and on a preliminary review of the Early Ranking written applications received by the Administrator having prior rankings, whether the Phase I Extension allowance reserve established by the Administrator pursuant to section 404(d) of the Act does or does not appear to be oversubscribed;

(4) If the Phase I Extension allowance reserve does not appear to be oversubscribed, the notice will provide that the applicant will be conditionally awarded allowances from the Phase I Extension reserve subject to the conditions specified in § 72.500(b).

(5) If the Phase I Extension allowance reserve appears to be oversubscribed the notice will specify the Early Ranking application's conditional order of receipt, as established pursuant to the phone queuing procedure in paragraph (c) of this section, and the ranking of the last Early Ranking application to be conditionally awarded allowances from the reserve.

(f) Each Early Ranking application received by EPA on a given day shall be deemed to have been received in the order established by the procedure specified in paragraphs (c) through (e) of this section.

(g) Early rankings and allowance awards pursuant to this subpart and § 72.42 shall be conditional allocations of awarded allowances and shall be subject to yearly demonstrations by the designated representative, as required by § 72.42, that the qualifying Phase I control technology has been installed by the applicant and has achieved 90% removal efficiency for sulfur dioxide.

APPENDIX A TO PART 72—EXISTING PHASE I AFFECTED UNITS

State	Plant name	Unit	Table A allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
AL	Colbert	1		20,886	20,609
AL	Colbert	2		28,052	22,237
AL	Colbert	3		24,397	21,985
AL	Colbert	4		24,626	18,537
AL	Colbert	5		41,847	51,952
AL	EC Gaston	1		19,348	23,747
AL	EC Gaston	2		19,023	20,363
AL	EC Gaston	3		17,205	21,466
AL	EC Gaston	4		15,715	23,620
AL	EC Gaston	5		47,526	68,507
FL	Big Bend	BB01		59,686	51,720
FL	Big Bend	BB02		48,835	44,129
FL	Big Bend	BB03		43,973	55,968
FL	Crist	6		39,985	38,655
FL	Crist	7		64,162	60,152
GA	Bowen	1BLR		53,893	46,093
GA	Bowen	2BLR		62,029	48,498
GA	Bowen	3BLR		81,636	61,074
GA	Bowen	4BLR		74,841	66,606
GA	Hammond	1		9,674	10,816
GA	Hammond	2		9,410	8,576
GA	Hammond	3		9,718	9,583
GA	Hammond	4		44,934	43,322
GA	Jack McDonough	MB1		35,734	31,904
GA	Jack McDonough	MB2		36,502	30,222
GA	Wansley	1		117,893	110,787
GA	Wansley	2		117,996	111,979
GA	Yates	Y1BR		7,405	8,694
GA	Yates	Y2BR		7,562	5,488
GA	Yates	Y3BR		5,839	6,500
GA	Yates	Y4BR		8,911	7,721
GA	Yates	Y5BR		8,587	8,503
GA	Yates	Y6BR		28,435	30,326
GA	Yates	Y7BR		27,564	24,968
IL	Baldwin	1		80,577	85,289
IL	Baldwin	2		82,081	89,755
IL	Baldwin	3		85,204	58,167
IL	Coffeen	01		32,999	22,034
IL	Coffeen	02		83,027	108,867
IL	Grand Tower	09		11,763	6,916
IL	Hennepin	2		28,552	28,097
IL	Joppa Steam	1		13,848	18,336
IL	Joppa Steam	2		11,282	18,021
IL	Joppa Steam	3		15,597	14,537
IL	Joppa Steam	4		15,018	16,813
IL	Joppa Steam	5		14,866	15,814
IL	Joppa Steam	6		12,913	18,944
IL	Kincaid	1		65,350	77,199
IL	Kincaid	2		93,779	67,506
IL	Meredosia	03		1,240	896
IL	Vermilion	2		13,445	12,625
IN	Bailly	7		32,867	26,485
IN	Bailly	8		44,008	35,169
IN	Breed	1		58,566	64,531
IN	Cayuga	1		34,996	53,861
IN	Cayuga	2		56,908	56,118

APPENDIX A TO PART 72—EXISTING PHASE I AFFECTED UNITS—Continued

State	Plant name	Unit	Table A allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
IN	Clifty Creek	1		43,892	49,641
IN	Clifty Creek	2		45,130	48,002
IN	Clifty Creek	3		46,951	50,300
IN	Clifty Creek	4		41,277	45,322
IN	Clifty Creek	5		46,607	48,516
IN	Clifty Creek	6		47,157	45,610
IN	Elmer W Stout	50		4,300	4,607
IN	Elmer W Stout	60		4,826	3,335
IN	Elmer W Stout	70		32,517	32,221
IN	FB Culley	2		15,200	14,252
IN	FB Culley	3		40,960	37,283
IN	Frank E Ratts	1SG1		17,748	17,515
IN	Frank E Ratts	2SG1		8,902	22,072
IN	Gibson	1		74,014	59,021
IN	Gibson	2		56,043	65,914
IN	Gibson	3		63,035	67,191
IN	Gibson	4		60,574	65,448
IN	HT Pritchard	6		11,373	9,234
IN	Michigan City	12		62.302	45,714
IN	Petersburg	1		25,125	25,194
IN	Petersburg	2		38,263	40,672
IN	R Gallagher	1		13,199	13,905
IN	R Gallagher	2		9,954	13,945
IN	R Gallagher	3		11,542	13,473
IN	R Gallagher	4		9,720	12,149
IN	Tanners Creek	U4		51,263	61,155
IN	Wabash River	1		5,522	4,834
IN	Wabash River	2		7,653	5,502
IN	Wabash River	3		4,332	2,607
IN	Wabash River	4		0	1,207
IN	Wabash River	5		5,368	3,621
IN	Wabash River	6		25,377	25,773
IN	Warrick	4		32,291	53,785
IA	Burlington	1		20,613	19,653
IA	Des Moines	11		—	—
IA	George Neal	1		2	1,239
IA	Milton L Kapp	2		26,063	26,301
IA	Prairie Creek	4		13,715	10,928
IA	Riverside	9		9,420	3,986
KS	Quindaro	2		14,251	4,278
KY	Coleman	C1		23,338	19,087
KY	Coleman	C2		20,863	18,534
KY	Coleman	C3		16,959	16,107
KY	Cooper	1		5,733	4,438
KY	Cooper	2		11,233	13,524
KY	EW Brown	1		9,756	9,479
KY	EW Brown	2		15,607	14,325
KY	EW Brown	3		38,341	36,192
KY	Elmer Smith	1		13,493	19,289
KY	Elmer Smith	2		21,034	26,870
KY	Ghent	2		12,814	7,300
KY	Green River	5		15,082	16,519
KY	HL Spurlock	1		31,048	21,226
KY	HMP&L Station 2	H1		18,841	20,958
KY	HMP&L Station 2	H2		24,158	17,764
KY	Paradise	3		162,748	127,854
KY	Shawnee	10		513	11,413
MD	CP Crane	1		14,488	11,084
MD	CP Crane	2		12,285	12,482
MD	Chalk Point	1		28,052	23,897
MD	Chalk Point	2		22,105	26,681
MD	Morgantown	1		49,252	42,429
MD	Morgantown	2		40,338	52,989
MI	JH Campbell	1		10,775	9,658
MI	JH Campbell	2		13,239	13,114
MN	High Bridge	12		1,447	1,763
MS	Jack Watson	4		30,444	31,973
MS	Jack Watson	5		58,796	46,093
MO	Asbury	1		63,339	67,438
MO	James River	5		12,663	9,479
MO	Labadie	1		70,676	50,984
MO	Labadie	2		67,443	61,755
MO	Labadie	3		58,701	67,296
MO	Labadie	4		58,347	70,025
MO	Montrose	1		1,841	2,345
MO	Montrose	2		2,768	1,625
MO	Montrose	3		2,814	2,825

APPENDIX A TO PART 72—EXISTING PHASE I AFFECTED UNITS—Continued

State	Plant name	Unit	Table A allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
MO	New Madrid	1		69,751	82,419
MO	New Madrid	2		53,418	94,083
MO	Sibley	3		45,718	36,140
MO	Sioux	1		32,865	45,148
MO	Sioux	2		38,722	35,448
MO	Thomas Hill	MB1		37,430	35,497
MO	Thomas Hill	MB2		56,310	48,995
NH	Merrimack	1		13,675	11,461
NH	Merrimack	2		37,362	34,521
NJ	BL England	1		15,509	13,730
NJ	BL England	2		18,181	19,185
NY	Dunkirk	3		20,297	15,292
NY	Dunkirk	4		15,605	21,939
NY	Greenidge	6		12,677	11,364
NY	Milliken	1		15,535	13,835
NY	Milliken	2		13,233	14,636
NY	Northport	1		11,579	11,267
NY	Northport	2		10,736	9,551
NY	Northport	3		11,872	10,817
NY	Port Jefferson	3		5,521	5,686
NY	Port Jefferson	4		4,564	5,315
OH	Ashtabula	7		41,013	44,396
OH	Avon Lake	8		0	—
OH	Avon Lake	11		—	—
OH	Avon Lake	12		66,867	64,237
OH	Cardinal	1		69,025	92,601
OH	Cardinal	2		74,158	77,631
OH	Conesville	1		16,976	15,561
OH	Conesville	2		16,188	14,516
OH	Conesville	3		15,017	14,533
OH	Conesville	4		71,292	91,061
OH	Eastlake	1		13,467	16,485
OH	Eastlake	2		17,326	12,530
OH	Eastlake	3		14,163	12,344
OH	Eastlake	4		30,545	25,309
OH	Eastlake	5		51,793	62,339
OH	Gen JM Gavin	1		171,963	198,136
OH	Gen JM Gavin	2		185,523	175,365
OH	Kyger Creek	1		45,088	49,926
OH	Kyger Creek	2		45,772	46,255
OH	Kyger Creek	3		43,907	41,161
OH	Kyger Creek	4		41,602	49,485
OH	Kyger Creek	5		45,644	49,912
OH	Miami Fort	5–1		1,751	1,368
OH	Miami Fort	5–2		0	0
OH	Miami Fort	6		19,071	21,614
OH	Miami Fort	7		57,341	61,955
OH	Muskingum River	1		48,698	54,595
OH	Muskingum River	2		37,314	45,904
OH	Muskingum River	3		38,064	51,528
OH	Muskingum River	4		51,269	39,634
OH	Muskingum River	5		135,195	126,078
OH	Niles	1		18,317	19,919
OH	Niles	2		18,130	20,487
OH	Picway	9		11,635	12,265
OH	RE Burger	5		4,964	6,485
OH	RE Burger	6		4,938	6,165
OH	RE Burger	7		17,390	24,475
OH	RE Burger	8		22,555	21,309
OH	WH Sammis	5		38,244	39,220
OH	WH Sammis	6		67,246	71,338
OH	WH Sammis	7		74,297	47,256
OH	Walter C Beckjord	5		15,001	22,530
OH	Walter C Beckjord	6		36,953	45,153
PA	Armstrong	1		18,944	17,293
PA	Armstrong	2		13,293	17,287
PA	Brunner Island	1		29,117	29,929
PA	Brunner Island	2		33,757	36,945
PA	Brunner Island	3		66,752	66,735
PA	Cheswick	1		40,059	43,092
PA	Conemaugh	1		108,568	88,361
PA	Conemaugh	2		92,115	83,240
PA	Hatfield's Ferry	1		60,337	53,113
PA	Hatfield's Ferry	2		63,915	53,067
PA	Hatfield's Ferry	3		55,076	60,199
PA	Martins Creek	1		12,634	13,549
PA	Martins Creek	2		9,125	14,599

APPENDIX A TO PART 72—EXISTING PHASE I AFFECTED UNITS—Continued

State	Plant name	Unit	Table A allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
PA	Portland	1		7,928	10,897
PA	Portland	2		20,206	15,037
PA	Shawville	1		13,002	14,306
PA	Shawville	2		14,249	12,098
PA	Shawville	3		17,864	16,540
PA	Shawville	4		14,579	18,212
PA	Sunbury	1A		6,223	6,173
PA	Sunbury	1B		6,223	6,173
PA	Sunbury	2A		6,223	6,173
PA	Sunbury	2B		6,223	6,173
PA	Sunbury	2B		14,103	16,444
PA	Sunbury	4		16,908	18,941
TN	Allen	1		17,696	28,128
TN	Allen	2		21,677	16,446
TN	Allen	3		24,950	10,638
TN	Cumberland	1		204,677	130,043
TN	Cumberland	2		152,954	196,954
TN	Gallatin	1		29,240	35,686
TN	Gallatin	2		36,839	27,435
TN	Gallatin	3		38,400	35,037
TN	Gallatin	4		43,128	25,763
TN	Johnsonville	1		12,377	9,750
TN	Johnsonville	10		8,124	3,639
TN	Johnsonville	2		12,806	8,313
TN	Johnsonville	3		11,749	8,759
TN	Johnsonville	4		7,456	4,003
TN	Johnsonville	5		7,146	9,302
TN	Johnsonville	6		980	9,261
TN	Johnsonville	7		11,816	4,704
TN	Johnsonville	8		11,525	9,338
TN	Johnsonville	9		10,607	4,385
WV	Albright	3		14,035	7,034
WV	Fort Martin	1		43,036	53,250
WV	Fort Martin	2		49,790	40,615
WV	Harrison	1		88,364	79,416
WV	Harrison	2		86,228	98,561
WV	Harrison	3		89,544	94,101
WV	Kammer	1		48,352	49,606
WV	Kammer	2		52,771	49,147
WV	Kammer	3		47,892	54,310
WV	Mitchell	1		31,298	36,753
WV	Mitchell	2		43,592	30,010
WV	Mt Storm	1		45,915	55,258
WV	Mt Storm	2		53,517	49,715
WV	Mt Storm	3		48,120	53,827
WI	Edgewater	4		37,340	42,233
WI	Genoa	B1		26,890	28,821
WI	Nelson Dewey	1		6,535	7,045
WI	Nelson Dewey	2		5,137	4,311
WI	North Oak Creek	1		3,645	3,191
WI	North Oak Creek	2		3,949	1,770
WI	North Oak Creek	3		0	—
WI	North Oak Creek	4		0	—
WI	Pulliam	8		15,154	11,270
WI	South Oak Creek	5		14,720	6,954
WI	South Oak Creek	6		11,970	9,103
WI	South Oak Creek	7		13,607	16,733
WI	South Oak Creek	8		11,526	18,798

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
AL	Barry	1		3,039	5,325
AL	Barry	2		3,536	4,903
AL	Barry	3		1,638	10,040
AL	Barry	4		11,598	14,418
AL	Barry	5		31,103	29,048
AL	Charles R Lowman	1		3,264	2,796
AL	Charles R Lowman	2		8,307	7,385
AL	Charles R Lowman	3		7,717	8,109
AL	Chickasaw	110		2	0

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
AL	Gadsden	1		2,627	1,236
AL	Gadsden	2		1,961	1,037
AL	Gorgas	5		1,259	38
AL	Gorgas	6		2,638	3,928
AL	Gorgas	7		2,727	4,029
AL	Gorgas	8		8,071	10,682
AL	Gorgas	9		9,321	12,282
AL	Gorgas	10		46,749	50,259
AL	Green County	1		20,913	18,324
AL	Green County	2		20,215	15,689
AL	James H Miller Jr	1		11,920	9,964
AL	James H Miller Jr	2		15,427	14,301
AL	James H Miller Jr	3		0	13,335
AL	Widows Creek	1		3,493	2,575
AL	Widows Creek	2		2,750	2,043
AL	Widows Creek	3		3,738	2,243
AL	Widows Creek	4		4,045	2,587
AL	Widows Creek	5		2,642	1,201
AL	Widows Creek	6		2,982	1,810
AL	Widows Creek	7		3,271	12,977
AL	Widows Creek	8		6,761	8,060
AZ	Agua Fria	1		22	89
AZ	Agua Fria	2		6	68
AZ	Agua Fria	3		24	198
AZ	Apache Station	1		0	0
AZ	Apache Station	2		0	2,573
AZ	Apache Station	3		3,802	4,932
AZ	Cholla	1		2,493	3,547
AZ	Cholla	2		5,404	7,506
AZ	Cholla	3		5,160	7,963
AZ	Cholla	4		3,933	3,922
AZ	Coronado	U1B		7,803	10,442
AZ	Coronado	U2B		7,691	8,630
AZ	De Moss Petrie	4		—	—
AZ	Irvington	1		0	0
AZ	Irvington	2		0	0
AZ	Irvington	3		0	0
AZ	Irvington	4		2,892	2,596
AZ	Kyrene	K-1		0	9
AZ	Kyrene	K-2		9	12
AZ	Navajo	1		24,588	25,004
AZ	Navajo	2		21,473	26,110
AZ	Navajo	3		24,441	21,961
AZ	Ocotillo	1		0	23
AZ	Ocotillo	2		0	5
AZ	Saguaro	1		-	0
AZ	Saguaro	2		-	0
AZ	Springerville	1		7,239	8,457
AZ	Springerville	2		0	0
AZ	West Phoenix	4		-	0
AZ	West Phoenix	6		-	1
AZ	Yuma Axis	1		0	0
AR	Carl Bailey	01		—	—
AR	Cecil Lynch	1		—	—
AR	Cecil Lynch	2		—	—
AR	Cecil Lynch	3		—	—
AR	Flint Creek	1		11,036	10,050
AR	Hamilton Moses	1		—	—
AR	Hamilton Moses	2		—	—
AR	Harvey Couch	1		0	0
AR	Harvey Couch	2		76	0
AR	Independence	1		9,734	7,199
AR	Independence	2		8,660	10,506
AR	Lake Catherine	1		0	0
AR	Lake Catherine	2		0	0
AR	Lake Catherine	3		0	0
AR	Lake Catherine	4		0	237
AR	McClellan	01		—	—
AR	Robert E Ritchie	1		256	59
AR	Robert E Ritchie	2		0	175
AR	Thomas Fitzhugh	1		—	—
AR	White Bluff	1		21,364	19,190
AR	White Bluff	2		20,959	19,242
CA	Alamitos	1		0	60
CA	Alamitos	2		11	27
CA	Alamitos	3		0	0
CA	Alamitos	4		227	194

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
CA	Alamitos	5		389	217
CA	Alamitos	6		164	400
CA	Avon	1		—	—
CA	Avon	2		—	—
CA	Avon	3		—	—
CA	Broadway	B1		16	8
CA	Broadway	B2		21	22
CA	Broadway	B3		31	12
CA	Contra Costa	1		0	0
CA	Contra Costa	2		0	0
CA	Contra Costa	3		0	0
CA	Contra Costa	4		0	0
CA	Contra Costa	5		0	0
CA	Contra Costa	6		0	0
CA	Contra Costa	7		0	0
CA	Contra Costa	8		0	0
CA	Contra Costa	9		19	0
CA	Contra Costa	10		192	882
CA	Cool Water	1		1	3
CA	Cool Water	2		0	2
CA	El Centro	2		15	12
CA	El Centro	3		294	263
CA	El Centro	4		402	88
CA	El Segundo	1		64	111
CA	El Segundo	2		34	25
CA	El Segundo	3		6	165
CA	El Segundo	4		231	192
CA	Encina	1		14	47
CA	Encina	2		205	173
CA	Encina	3		29	112
CA	Encina	4		167	346
CA	Encina	5		813	775
CA	Etiwanda	1		0	1
CA	Etiwanda	2		0	1
CA	Etiwanda	3		227	271
CA	Etiwanda	4		154	127
CA	Glenarm	14		—	—
CA	Glenarm	15		—	—
CA	Glenarm	16		—	—
CA	Glenarm	17		—	—
CA	Grayson	4		12	15
CA	Grayson	5		19	29
CA	Harbor Gen Station	1		2	-
CA	Harbor Gen Station	2		0	-
CA	Harbor Gen Station	3		7	7
CA	Harbor Gen Station	4		10	8
CA	Harbor Gen Station	5		9	16
CA	Haynes Gen Station	1		56	70
CA	Haynes Gen Station	2		22	106
CA	Haynes Gen Station	3		206	304
CA	Haynes Gen Station	4		80	362
CA	Haynes Gen Station	5		114	392
CA	Haynes Gen Station	6		12	293
CA	Highgrove	1		0	0
CA	Highgrove	2		0	0
CA	Highgrove	3		0	1
CA	Highgrove	4		0	0
CA	Humboldt Bay	1		324	42
CA	Humboldt Bay	2		289	45
CA	Hunters Point	3		4	3
CA	Hunters Point	4		3	2
CA	Hunters Point	5		1	7
CA	Hunters Point	6		2	5
CA	Hunters Point	7		7	13
CA	Huntington Beach	1		126	249
CA	Huntington Beach	2		197	0
CA	Huntington Beach	3		7	0
CA	Huntington Beach	4		7	0
CA	Kern	1		—	—
CA	Kern	2		—	—
CA	Kern	3		—	—
CA	Kern	4		—	—
CA	Magnolia	M4		0	23
CA	Mandalay	1		327	220
CA	Mandalay	2		339	98
CA	Martinez	1		—	—
CA	Martinez	2		—	—

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
CA	Martinez	3		—	—
CA	Morro Bay	1		127	101
CA	Morro Bay	2		97	142
CA	Morro Bay	3		1,009	573
CA	Morro Bay	4		407	426
CA	Moss Landing	1		0	0
CA	Moss Landing	2		0	0
CA	Moss Landing	3		0	0
CA	Moss Landing	4		0	0
CA	Moss Landing	5		0	0
CA	Moss Landing	6		0	0
CA	Moss Landing	6–1		1,887	1,707
CA	Moss Landing	7		0	0
CA	Moss Landing	7–1		99	383
CA	Moss Landing	8		0	0
CA	Oleum	1		—	—
CA	Oleum	2		—	—
CA	Oleum	3		—	—
CA	Oleum	4		—	—
CA	Oleum	5		—	—
CA	Oleum	6		—	—
CA	Olive	01		0	5
CA	Olive	02		4	47
CA	Ormond Beach	1		109	379
CA	Ormond Beach	2		476	433
CA	Pittsburg	1		105	167
CA	Pittsburg	2		169	149
CA	Pittsburg	3		213	88
CA	Pittsburg	4		165	161
CA	Pittsburg	5		628	486
CA	Pittsburg	6		964	988
CA	Pittsburg	7		0	16
CA	Potrero	3–1		694	431
CA	Redondo Beach	5		0	7
CA	Redondo Beach	6		16	7
CA	Redondo Beach	7		0	24
CA	Redondo Beach	8		0	27
CA	Redondo Beach	11		0	0
CA	Redondo Beach	12		0	0
CA	Redondo Beach	13		0	0
CA	Redondo Beach	14		0	0
CA	Redondo Beach	15		0	0
CA	Redondo Beach	16		0	0
CA	Redondo Beach	17		0	0
CA	San Bernardino	1		0	2
CA	San Bernardino	2		0	2
CA	Scattergood Gen Sta	1		134	115
CA	Scattergood Gen Sta	2		135	115
CA	Scattergood Gen Sta	3		0	0
CA	Silver Gate	1		—	—
CA	Silver Gate	2		—	—
CA	Silver Gate	3		—	—
CA	Silver Gate	4		—	—
CA	Silver Gate	5		—	—
CA	Silver Gate	6		—	—
CA	South Bay	1		415	292
CA	South Bay	2		291	189
CA	South Bay	3		83	176
CA	South Bay	4		18	48
CA	Valley Gen Sta	1		0	16
CA	Valley Gen Sta	2		0	37
CA	Valley Gen Sta	3		53	12
CA	Valley Gen Sta	4		60	100
CO	Arapahoe	1		190	590
CO	Arapahoe	2		207	722
CO	Arapahoe	3		389	687
CO	Arapahoe	4		1,746	2,431
CO	Cameo	2		1,196	849
CO	Cherokee	1		133	2,414
CO	Cherokee	2		1,650	1,790
CO	Cherokee	3		3,558	2,909
CO	Cherokee	4		5,624	5,029
CO	Comanche	1		6,164	6,467
CO	Comanche	2		6,828	5,865
CO	Craig	C1		9,765	11,500
CO	Craig	C2		10,496	10,274
CO	Craig	C3		10,544	3,188

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
CO	Hayden	H1		4,122	5,729
CO	Hayden	H2		8,376	8,116
CO	Martin Drake	5		950	651
CO	Martin Drake	6		1,853	1,781
CO	Martin Drake	7		1,745	2,579
CO	Nucla	1		3,138	2,495
CO	Pawnee	1		21,218	9,449
CO	Rawhide	101		1,409	1,370
CO	Ray D Nixon	1		5,022	4,795
CO	Valmont	5		3,471	4,781
CO	Valmont	11		—	—
CO	Valmont	12		—	—
CO	Valmont	13		—	—
CO	Valmont	14		—	—
CO	Valmont	21		—	—
CO	Valmont	22		—	—
CO	Valmont	23		—	—
CO	Valmont	24		—	—
CO	Zuni	1		0	0
CO	Zuni	2		0	0
CO	Zuni	3		0	0
CT	Bridgeport Harbor	BHB1		1,657	2,347
CT	Bridgeport Harbor	BHB2		4,256	4,922
CT	Bridgeport Harbor	BHB3		8,881	9,055
CT	Devon	3		1,177	1,006
CT	Devon	4A		198	269
CT	Devon	4B		198	269
CT	Devon	5A		156	288
CT	Devon	5B		156	288
CT	Devon	6		1,064	1,103
CT	Devon	7		2,651	2,443
CT	Devon	8		2,342	2,917
CT	English	EB13		152	178
CT	English	EB14		180	190
CT	Middletown	1		480	541
CT	Middletown	2		1,004	1,235
CT	Middletown	3		2,886	3,085
CT	Middletown	4		2,657	2,638
CT	Montville	5		1,389	1,196
CT	Montville	6		5,416	7,365
CT	New Haven Harbor	NHB1		13,143	13,188
CT	Norwalk Harbor	1		5,314	5,849
CT	Norwalk Harbor	2		5,621	5,562
CT	South Meadow	11		956	3,057
CT	South Meadow	12		834	3,141
CT	South Meadow	13		1,021	2,836
DE	Delaware City	B1		11,136	9,778
DE	Delaware City	B2		11,402	8,951
DE	Delaware City	B3		10,118	11,030
DE	Delaware City	B4		10,258	11,096
DE	Edge Moor	3		3,328	3,467
DE	Edge Moor	4		6,229	7,066
DE	Edge Moor	5		10,183	8,562
DE	Indian River	1		6,338	6,295
DE	Indian River	2		8,235	4,194
DE	Indian River	3		13,308	11,316
DE	Indian River	4		33,694	10,805
DE	McKee Run	3		4,383	4,854
DC	Benning	15		1,452	2,009
DC	Benning	16		1,545	2,025
FL	Anclote	1		5,049	11,222
FL	Anclote	2		8,337	11,009
FL	Arvah B Hopkins	1		13	108
FL	Arvah B Hopkins	2		1,224	171
FL	Avon Park	2		—	—
FL	Big Bend	BB04		8,731	8,623
FL	CD McIntosh Jr	1		1,822	1,034
FL	CD McIntosh Jr	2		214	113
FL	CD McIntosh Jr	3		10,457	12,089
FL	Cape Canaveral	PCC1		3,059	2,678
FL	Cape Canaveral	PCC2		2,829	3,657
FL	Crist	1		0	0
FL	Crist	2		0	0
FL	Crist	3		0	0
FL	Crist	4		8,619	11,033
FL	Crist	5		11,836	8,053
FL	Crystal River	1		22,447	17,497

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
FL	Crystal River	2		21,957	21,622
FL	Crystal River	4		24,729	25,105
FL	Crystal River	5		25,389	24,817
FL	Cutler	PCU5		0	0
FL	Cutler	PCU6		0	0
FL	Deerhaven	B1		15	72
FL	Deerhaven	B2		7,918	7,089
FL	FJ Gannon	GB01		5,948	4,569
FL	FJ Gannon	GB02		5,729	6,412
FL	FJ Gannon	GB03		7,271	8,120
FL	FJ Gannon	GB04		9,170	7,720
FL	FJ Gannon	GB05		10,780	13,042
FL	FJ Gannon	GB06		17,884	14,034
FL	Fort Myers	PFM1		2,147	1,891
FL	Fort Myers	PFM2		9,680	9,139
FL	GE Turner	2		0	0
FL	GE Turner	3		1,076	2,625
FL	GE Turner	4		1,311	2,416
FL	Henry D King	7		0	0
FL	Henry D King	8		0	18
FL	Higgins	1		904	1,552
FL	Higgins	2		959	1,930
FL	Higgins	3		909	1,931
FL	Hookers Point	HB01		—	—
FL	Hookers Point	HB02		—	—
FL	Hookers Point	HB03		—	—
FL	Hookers Point	HB04		—	—
FL	Hookers Point	HB05		—	—
FL	Hookers Point	HB06		—	—
FL	Indian River	1		418	420
FL	Indian River	2		1,638	1,134
FL	Indian River	3		592	1,137
FL	JD Kennedy	8		0	0
FL	JD Kennedy	9		15	17
FL	JD Kennedy	10		0	154
FL	JR Kelly	JRK8		8	19
FL	Larsen Memorial	7		84	94
FL	Lauderdale	PFL4		263	500
FL	Lauderdale	PFL5		296	263
FL	Manatee	PMT1		10,187	12,133
FL	Manatee	PMT2		13,957	12,156
FL	Martin	PMR1		2,939	3,057
FL	Martin	PMR2		4,340	2,471
FL	Northside	1		9,751	3,289
FL	Northside	2		0	0
FL	Northside	3		14,736	8,370
FL	PL Bartow	1		5,323	7,409
FL	PL Bartow	2		5,704	8,116
FL	PL Bartow	3		8,322	12,337
FL	Port Everglades	PPE1		4,203	4,151
FL	Port Everglades	PPE2		2,667	4,451
FL	Port Everglades	PPE3		5,390	3,105
FL	Port Everglades	PPE4		6,743	5,901
FL	Putnam	HRSG11		—	—
FL	Putnam	HRSG12		—	—
FL	Putnam	HRSG21		—	—
FL	Putnam	HRSG22		—	—
FL	Riviera	PRV2		0	0
FL	Riviera	PRV3		2,422	3,311
FL	Riviera	PRV4		2,077	3,337
FL	SO Purdom	7		30	88
FL	Sanford	PSN3		49	172
FL	Sanford	PSN4		1,345	2,025
FL	Sanford	PSN5		2,001	5,423
FL	Scholz	1		8,226	8,836
FL	Scholz	2		9,088	8,615
FL	Seminole	1		3,801	9,178
FL	Seminole	2		13,199	12,643
FL	Smith	1		25,906	16,062
FL	Smith	2		22,655	23,197
FL	Southside	1		0	0
FL	Southside	2		0	0
FL	Southside	3		0	0
FL	Southside	4		78	28
FL	Southside	5		539	0
FL	St Johns River Power PK	1		10,967	9,417
FL	St Johns River Power PK	2		6,467	11,157

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
FL	Stanton Energy	1		5,868	4,755
FL	Stock Island	1		1,044	1,901
FL	Suwannee River	1		393	573
FL	Suwannee River	2		422	598
FL	Suwannee River	3		342	105
FL	Tom G Smith	S-3		0	117
FL	Tom G Smith	S-4		1	0
FL	Turkey Point	PTP1		5,448	3,976
FL	Turkey Point	PTP2		3,533	3,547
FL	Vero Beach Municipal	3		0	35
FL	Vero Beach Municipal	4		3	17
GA	Arkwright	1		2,060	1,824
GA	Arkwright	2		1,854	2,275
GA	Arkwright	3		2,195	2,240
GA	Arkwright	4		1,702	2,326
GA	Atkinson	A1A		0	0
GA	Atkinson	A1B		0	0
GA	Atkinson	A2		0	0
GA	Atkinson	A3		0	0
GA	Atkinson	A4		0	0
GA	Harllee Branch	1		17,617	17,466
GA	Harllee Branch	2		18,294	19,838
GA	Harllee Branch	3		30,762	34,255
GA	Harllee Branch	4		31,714	32,658
GA	McIntosh	1		7,279	8,062
GA	McManus	1		221	64
GA	McManus	2		471	145
GA	Mitchell	3		7,767	7,878
GA	Port Wentworth	1		2,220	3,086
GA	Port Wentworth	2		1,684	2,518
GA	Port Wentworth	3		4,412	4,337
GA	Port Wentworth	4		642	39
GA	Riverside	8		—	—
GA	Scherer	1		6,351	6,882
GA	Scherer	2		8,329	4,392
GA	Scherer	3		10,327	5,421
GA	Scherer	4		0	7,294
IL	Collins	1		1,063	389
IL	Collins	2		555	490
IL	Collins	3		1,259	642
IL	Collins	4		781	368
IL	Collins	5		465	717
IL	Collins	7		931	608
IL	Crawford	7		931	608
IL	Crawford	8		1,928	1,108
IL	Dallman	31		8,808	12,615
IL	Dallman	32		10,952	10,452
IL	Dallman	33		5,915	5,627
IL	Duck Creek	1		11,640	11,618
IL	ED Edwards	1		3,430	3,350
IL	ED Edwards	2		8,555	10,661
IL	ED Edwards	3		11,949	9,522
IL	Fisk	19		1,389	1,565
IL	Grand Tower	07		533	1,479
IL	Grand Tower	08		515	1,482
IL	Havana	1		53	20
IL	Havana	2		53	26
IL	Havana	3		53	27
IL	Havana	4		53	37
IL	Havana	5		53	45
IL	Havana	6		53	146
IL	Havana	7		53	88
IL	Havana	8		53	128
IL	Havana	9		6,336	8,735
IL	Hennepin	1		7,067	8,260
IL	Hutsonville	05		6,556	4,940
IL	Hutsonville	06		5,7.4	3,927
IL	Joilet 9	5		4,529	2,341
IL	Joliet 29	71		2,873	3,224
IL	Joliet 29	72		3,017	3,303
IL	Joliet 29	81		2,693	2,605
IL	Joliet 29	82		2,838	2,268
IL	Lakeside	7		1,830	891
IL	Lakeside	8		2,118	1,859
IL	Marion	1		603	2,445
IL	Marion	2		1,642	2,038
IL	Marion	3		1,386	2,346

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
IL	Marion	4		6,773	5,846
IL	Meredosia	01		1,510	765
IL	Meredosia	02		1,038	1,017
IL	Meredosia	04		1,057	892
IL	Meredosia	05		28,503	21,259
IL	Meredosia	06		89	37
IL	Newton	1		17,282	16,074
IL	Newton	2		6,218	7,667
IL	Powerton	51		3,130	3,781
IL	Powerton	52		3,239	4,494
IL	Powerton	61		6,410	4,008
IL	Powerton	62		6,572	3,663
IL	RS Wallace	6		—	—
IL	RS Wallace	7		—	—
IL	RS Wallace	8		—	—
IL	RS Wallace	9		—	—
IL	RS Wallace	10		—	—
IL	Venice	1		0	2
IL	Venice	2		0	0
IL	Venice	3		0	1
IL	Venice	4		0	0
IL	Venice	5		0	3
IL	Venice	6		0	3
IL	Venice	7		1	0
IL	Venice	8		1	0
IL	Vermilion	1		8,256	8,796
IL	Waukegan	7		4,753	4,431
IL	Waukegan	8		1,868	1,447
IL	Waukegan	17		343	2
IL	Will County	1		613	598
IL	Will County	2		890	998
IL	Will County	3		1,633	1,181
IL	Will County	4		6,287	4,367
IL	Wood River	1		0	0
IL	Wood River	2		0	1
IL	Wood River	3		0	1
IL	Wood River	4		1,859	1,415
IL	Wood River	5		10,017	9,909
IN	AB Brown	1		5,726	7,024
IN	AB Brown	2		4,493	4,138
IN	Dean H Mitchell	4		3,104	2,997
IN	Dean H Mitchell	5		3,554	1,990
IN	Dean H Mitchell	6		3,416	2,496
IN	Dean H Mitchell	11		2,878	2,491
IN	Edwardsport	6–1		5	1
IN	Edwardsport	7–1		1,845	1,511
IN	Edwardsport	7–2		1,610	1,261
IN	Edwardsport	8–1		1,111	1,249
IN	Elmer W Stout	1		—	—
IN	Elmer W Stout	2		—	—
IN	Elmer W Stout	3		—	—
IN	Elmer W Stout	4		—	—
IN	Elmer W Stout	5		—	—
IN	Elmer W Stout	6		—	—
IN	Elmer W Stout	7		—	—
IN	Elmer W Stout	8		—	—
IN	Elmer W Stout	9		3	0
IN	Elmer W Stout	10		3	1
IN	FB Culley	1		6,951	6,725
IN	Gibson	5		9,478	7,889
IN	HT Pritchard	1		4	1
IN	HT Pritchard	2		5	2
IN	HT Pritchard	3		797	885
IN	HT Pritchard	4		1,328	2,376
IN	HT Pritchard	5		1,403	795
IN	Merom	1SG1		13,561	16,131
IN	Merom	2SG1		14,520	14,127
IN	Michigan City	4		1,539	0
IN	Michigan City	5		2,408	0
IN	Michigan City	6		1,669	0
IN	Noblesville	1		430	202
IN	Noblesville	2		57	198
IN	Noblesville	3		290	240
IN	Petersburg	3		17,960	17,681
IN	Petersburg	4		20,524	18,498
IN	RM Schahfer	14		8,177	21,692
IN	RM Schahfer	15		2,580	13,389

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
IN	RM Schahfer	17		4,453	5,877
IN	RM Schahfer	18		4,976	5,673
IN	Rockport	MB1		21,436	28,211
IN	Rockport	MB2		0	3,082
IN	State Line	3		863	514
IN	State Line	4		2,327	1,381
IN	Tanners Creek	U1		2,967	3,901
IN	Tanners Creek	U2		3,849	3,338
IN	Tanners Creek	U3		3,512	4,407
IN	Whitewater Valley	1		3,488	3,418
IN	Whitewater Valley	2		9,396	9,048
IA	Ames	7		257	93
IA	Ames	8		603	767
IA	Council Bluffs	1		841	620
IA	Council Bluffs	2		1,451	1,066
IA	Council Bluffs	3		14,208	11,259
IA	Des Moines	10		—	—
IA	Dubuque	1		3,400	5,425
IA	Dubuque	5		1,269	2,641
IA	Earl F Wisdom	1		1,183	1,062
IA	Fair Station	2		7,015	5,294
IA	George Neal	2		6,052	4,301
IA	George Neal	3		8,889	7,642
IA	George Neal	4		10,844	15,877
IA	Lansing	3		1,577	2,814
IA	Lansing	4		4,681	3,214
IA	Louisa	101		13,153	14,274
IA	Maynard Station	1		—	—
IA	Muscatine	8		5,151	7,849
IA	Muscatine	9		1,902	1,821
IA	Ottumwa	1		13,364	13,715
IA	Pella	6		961	1,077
IA	Pella	7		1,448	1,317
IA	Pella	8		0	0
IA	Prairie Creek	3		1,941	2,187
IA	Riverside	6		1,029	1,137
IA	Riverside	7		1,141	1,279
IA	Riverside	8		1,055	1,074
IA	Sixth Street	1		9,600	10,537
IA	Sixth Street	2		0	0
IA	Sixth Street	3		0	0
IA	Sixth Street	4		0	0
IA	Sixth Street	5		0	0
IA	Streeter Station	7		2,182	1,549
IA	Sutherland	1		1,062	1,423
IA	Sutherland	2		501	2,927
IA	Sutherland	3		9,128	1,978
KS	Arthur Mullergren	3		0	0
KS	Cimarron River	1		0	0
KS	Coffeyville	4		0	0
KS	East 12th Street Plant	4		0	0
KS	Garden City	S–2		—	—
KS	Gordon Evans	1		92	6
KS	Gordon Evans	2		439	0
KS	Holcomb	SGU1		2,824	2,101
KS	Hutchinson	1		0	0
KS	Hutchinson	2		0	0
KS	Hutchinson	3		0	0
KS	Hutchinson	4		0	63
KS	Jeffrey Energy Center	1		15,675	13,597
KS	Jeffrey Energy Center	2		14,308	14,552
KS	Jeffrey Energy Center	3		16,339	13,891
KS	Judson Large	4		0	0
KS	Kaw	1		2,285	754
KS	Kaw	2		2,768	768
KS	Kaw	3		0	0
KS	LA Cygne	1		36,117	70,772
KS	LA Cygne	2		13,615	12,573
KS	Lawrence	2		0	0
KS	Lawrence	3		876	361
KS	Lawrence	4		2,895	2,356
KS	Lawrence	5		12,454	8,617
KS	McPherson 2	1		0	0
KS	Murray Gill	1		0	0
KS	Murray Gill	2		0	0
KS	Murray Gill	3		0	47
KS	Murray Gill	4		0	13

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
KS	Nearman Creek	N1		4,610	6,100
KS	Neosho	7		—	—
KS	Qunidaro	1		4,806	6,597
KS	Ripley	—		—	—
KS	Riverton	39		2,244	2,181
KS	Riverton	40		3,900	4,999
KS	Tecumseh	9		2,324	1,863
KS	Tecumseh	10		4,070	3,493
KY	Big Sandy	BSU1		14,909	18,132
KY	Big Sandy	BSU2		38,232	43,095
KY	Cane Run	1		—	—
KY	Cane Run	2		—	—
KY	Cane Run	3		0	0
KY	Cane Run	4		1,580	3,857
KY	Cane Run	5		4,352	3,842
KY	Cane Run	6		4,927	6,550
KY	DB Wilson	W1		10,231	9,374
KY	Dale	3		2,146	1,637
KY	Dale	4		2,034	1,837
KY	East Bend	2		26,314	20,885
KY	Ghent	1		52,751	75,645
KY	Ghent	3		11,760	9,208
KY	Ghent	4		14,598	10,343
KY	Green River	1		18	8
KY	Green River	2		6	3
KY	Green River	3		12	11
KY	Green River	4		7,193	5,619
KY	HL Spurlock	2		15,942	11,498
KY	Henderson I	6		710	638
KY	Mill Creek	1		7,677	8,362
KY	Mill Creek	2		8,941	10,601
KY	Mill Creek	3		11,908	13,155
KY	Mill Creek	4		15,141	14,729
KY	Paradise	1		19,197	14,431
KY	Paradise	2		14,713	17,820
KY	Pineville	3		440	307
KY	RD Green	G1		6,152	6,654
KY	RD Green	G2		7,492	6,195
KY	Robert Reid	R1		6,772	—
KY	Shawnee	1		1,669	1,532
KY	Shawnee	2		3,756	2,841
KY	Shawnee	3		4,137	2,771
KY	Shawnee	4		3,701	1,952
KY	Shawnee	5		3,835	3,257
KY	Shawnee	6		3,015	2,057
KY	Shawnee	7		4,046	2,984
KY	Shawnee	8		4,240	2,441
KY	Shawnee	9		19,512	15,553
KY	Trimble County	1		—	—
KY	Tyrone	1		0	0
KY	Tyrone	2		0	0
KY	Tyrone	3		0	0
KY	Tyrone	4		0	0
KY	Tyrone	5		844	1,039
LA	AB Paterson	3		—	—
LA	AB Paterson	4		—	—
LA	Arsenal Hill	5A		0	0
LA	Big Cajun 1	1B1		1	2
LA	Big Cajun 1	1B2		0	0
LA	Big Cajun 2	2B1		15,862	14,592
LA	Big Cajun 2	2B2		13,205	17,708
LA	Big Cajun 2	2B3		13,040	15,281
LA	Coughlin	5		—	—
LA	Coughlin	6		0	0
LA	Coughlin	7		0	5
LA	DG Hunter	3		0	2
LA	DG Hunter	4		0	0
LA	Doc Bonin	1		0	0
LA	Doc Bonin	2		0	0
LA	Doc Bonin	3		0	0
LA	Dolet Hills	1		10,280	9,857
LA	Houma	15		0	0
LA	Houma	16		0	0
LA	Lieberman	3		0	0
LA	Lieberman	4		0	0
LA	Little Gypsy	1		3	12
LA	Little Gypsy	2		7	14

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
LA	Little Gypsy	3		10	13
LA	Louisiana 1	1A		0	0
LA	Louisiana 1	2A		0	0
LA	Louisiana 1	3A		0	0
LA	Louisiana 2	10		—	—
LA	Louisiana 2	11		—	—
LA	Louisiana 2	12		—	—
LA	Michoud	1		4	46
LA	Michoud	2		8	81
LA	Michoud	3		22	9
LA	Monroe	11		0	—
LA	Monroe	12		0	—
LA	Morgan City	4		0	0
LA	Natchitoches	10		0	0
LA	Ninemile Point	1		8	18
LA	Ninemile Point	2		3	22
LA	Ninemile Point	3		25	16
LA	Ninemile Point	4		2	7
LA	Ninemile Point	5		20	91
LA	Opelousas	10		0	—
LA	RS Nelson	1		0	0
LA	RS Nelson	2		0	0
LA	RS Nelson	3		0	0
LA	RS Nelson	4		0	0
LA	RS Nelson	6		18,145	18,844
LA	Rodemacher	1		0	24
LA	Rodemacher	2		18,597	14,042
LA	Ruston	2		0	0
LA	Ruston	3		0	0
LA	Sterlington	7AB		8	19
LA	Sterlington	10		0	8
LA	Teche	2		0	0
LA	Teche	3		0	0
LA	Waterford 1 & 2	1		342	295
LA	Waterford 1 & 2	2		332	232
LA	Willow Glen	1		0	0
LA	Willow Glen	2		0	0
LA	Willow Glen	3		0	0
LA	Willow Glen	4		0	0
LA	Willow Glen	5		425	18
ME	Graham Station	5		239	86
ME	Mason Steam	3		43	75
ME	Mason Steam	4		33	70
ME	Mason Steam	5		19	65
ME	William F Wyman	1		1,295	1,244
ME	William F Wyman	2		854	1,239
ME	William F Wyman	3		4,795	4,228
ME	William F Wyman	4		6,916	7,637
MD	Brandon Shores	1		21,554	25,236
MD	Chalk Point	3		11,383	18,080
MD	Chalk Point	4		2,211	3,610
MD	Dickerson	1		13,774	12,392
MD	Dickerson	2		15,080	12,245
MD	Dickerson	3		13,303	15,626
MD	Gould Street	3		1,196	1,941
MD	Herbert A Wagner	1		759	877
MD	Herbert A Wagner	2		4,099	5,488
MD	Herbert A Wagner	3		13,548	8,399
MD	Herbert A Wagner	4		2,524	7,586
MD	RP Smith	9		602	589
MD	RP Smith	11		4,125	4,175
MD	Riverside	1		337	1,087
MD	Riverside	2		209	762
MD	Riverside	3		356	906
MD	Riverside	4		688	640
MD	Riverside	5		431	1,100
MD	Vienna	8		5,880	6,710
MD	Westport	3		335	884
MD	Westport	4		428	1,214
MA	Brayton Point	1		15,254	17,516
MA	Brayton Point	2		14,566	16,634
MA	Brayton Point	3		30,533	29,270
MA	Brayton Point	4		18,613	21,233
MA	Canal	1		35,718	33,807
MA	Canal	2		32,781	38,397
MA	Cannon Street	3		541	333
MA	Cleary Flood	8		523	651

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
MA	Cleary Flood	9		1,404	1,625
MA	Kendall Square	1		59	119
MA	Kendall Square	2		49	118
MA	Kendall Square	3		292	191
MA	Mount Tom	1		10,601	9,864
MA	Mystic	4		4,441	4,601
MA	Mystic	5		2,394	2,009
MA	Mystic	6		4,302	3,379
MA	Mystic	7		10,404	9,218
MA	New Boston	1		9,458	7,752
MA	New Boston	2		9,171	5,367
MA	Salem Harbor	1		4,715	5,729
MA	Salem Harbor	2		4,240	6,168
MA	Salem Harbor	3		10,015	10,057
MA	Salem Harbor	4		27,086	28,194
MA	Somerset	1		0	0
MA	Somerset	2		0	0
MA	Somerset	3		0	0
MA	Somerset	4		0	0
MA	Somerset	5		0	0
MA	Somerset	6		0	0
MA	Somerset	7		4,188	4,792
MA	Somerset	8		6,466	6,890
MA	West Springfield	1		532	520
MA	West Springfield	2		470	492
MA	West Springfield	3		3,744	864
MI	BC Cobb	1		711	1,044
MI	BC Cobb	2		729	860
MI	BC Cobb	3		600	845
MI	BC Cobb	4		6,060	6,357
MI	BC Cobb	5		6,027	5,717
MI	Belle River	1		16,447	14,668
MI	Belle River	2		16,537	14,296
MI	Conners Creek	15		736	—
MI	Conners Creek	16		614	—
MI	Conners Creek	17		787	—
MI	Conners Creek	18		0	—
MI	Dan E Karn	1		8,041	4,729
MI	Dan E Karn	2		6,414	11,252
MI	Dan E Karn	3		1,539	1,082
MI	Dan E Karn	4		2,209	2,508
MI	Delray	7		0	—
MI	Delray	8		0	—
MI	Delray	9		0	—
MI	Delray	10		0	—
MI	Delray	11		0	—
MI	Delray	12		0	—
MI	Delray	9		0	—
MI	Delray	10		0	—
MI	Delray	12		0	—
MI	Eckert Station	1		1,226	1,376
MI	Eckert Station	2		1,329	1,253
MI	Eckert Station	3		1,347	1,486
MI	Eckert Station	4		2,211	2,967
MI	Eckert Station	5		2,942	2,622
MI	Eckert Station	6		2,437	2,341
MI	Endicott Generating	1		8,314	9,169
MI	Erickson	1		6,728	6,664
MI	Greenwood	1		1,720	1,997
MI	Harbor Beach	1		1,422	1,858
MI	JB Sims	3		8,871	8,517
MI	JC Weadock	7		6,248	4,617
MI	JC Weadock	8		5,601	6,480
MI	JH Campbell	3		22,134	24,279
MI	JR Whiting	1		4,489	4,134
MI	JR Whiting	2		4,145	4,617
MI	JR Whiting	3		5,239	5,533
MI	James De Young	5		1,189	1,158
MI	Marysville	9		280	—
MI	Marysville	10		177	—
MI	Marysville	11		235	—
MI	Marysville	12		125	—
MI	Mistersky	5		453	360
MI	Mistersky	6		666	684
MI	Mistersky	7		0	33
MI	Monroe	1		28,389	30,675
MI	Monroe	2		37,317	29,659

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
MI	Monroe	3		33,138	29,947
MI	Monroe	4		39,363	30,013
MI	Presque Isle	2		322	96
MI	Presque Isle	3		1,449	1,458
MI	Presque Isle	4		1,547	1,429
MI	Presque Isle	5		2,645	2,829
MI	Presque Isle	6		3,038	2,512
MI	Presque Isle	7		2,925	2,782
MI	Presque Isle	8		3,010	2,710
MI	Presque Isle	9		2,856	3,107
MI	River Rouge	1		0	0
MI	River Rouge	2		8,915	7,027
MI	River Rouge	3		8,422	8,669
MI	Shiras	3		1,242	1,128
MI	St Clair	1		3,222	4,223
MI	St Clair	2		3,886	3,570
MI	St Clair	3		3,875	3,494
MI	St Clair	4		4,196	3,990
MI	St Clair	5		0	0
MI	St Clair	6		10,712	9,574
MI	St Clair	7		10,552	17,569
MI	Trenton Channel	9A		15,958	14,780
MI	Trenton Channel	16		2,705	2,804
MI	Trenton Channel	17		83	0
MI	Trenton Channel	18		2,483	2,441
MI	Trenton Channel	19		0	0
MI	Wyandotte	7		1,125	1,295
MN	Allen S King	1		13,820	33,119
MN	Black Dog	1		966	418
MN	Black Dog	2		1,984	492
MN	Black Dog	3		2,735	1,460
MN	Black Dog	4		3,865	3,196
MN	Clay Boswell	1		1,987	2,515
MN	Clay Boswell	2		2,472	1
MN	Clay Boswell	3		18,178	15,433
MN	Clay Boswell	4		24,043	22,665
MN	Fox Lake	3		2,145	2,094
MN	High Bridge	9		158	0
MN	High Bridge	10		297	905
MN	High Bridge	11		1,412	1,323
MN	Hoot Lake	2		530	822
MN	Hoot Lake	3		372	878
MN	ML Hibbard	3		289	469
MN	ML Hibbard	4		460	386
MN	Minnesota Valley	3		244	218
MN	Northeast Station	NEPP		421	342
MN	Riverside	6		2,768	3,781
MN	Riverside	7		3,326	3,682
MN	Riverside	8		7,917	9,748
MN	Sherburne County	1		28,079	19,643
MN	Sherburne County	2		24,160	20,230
MN	Sherburne County	3		11,633	11,053
MN	Silver Lake	4		1,416	2,382
MN	Syl Laskin	1		153	196
MN	Syl Laskin	2		484	439
MS	Baxter Wilson	1		156	379
MS	Baxter Wilson	2		3,624	6,959
MS	Delta	1		0	0
MS	Delta	2		0	62
MS	Gerald Andrus	1		6,239	4,523
MS	Jack Watson	1		0	3
MS	Jack Watson	2		0	0
MS	Jack Watson	3		1	1
MS	Moselle	1		7	57
MS	Moselle	2		26	126
MS	Moselle	3		0	98
MS	Natchez	1		—	—
MS	RD Morrow	1		6,160	5,440
MS	RD Morrow	2		5,521	6,628
MS	Rex Brown	1A		0	0
MS	Rex Brown	1B		0	0
MS	Rex Brown	3		0	25
MS	Rex Brown	4		43	46
MS	Sweatt	1		248	13
MS	Sweatt	2		256	32
MS	Victor J Daniel Jr	1		14,968	7,847
MS	Victor J Daniel Jr	2		14,354	7,471

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
MO	Blue Valley	3		2,079	1,064
MO	Chamois	2		7,444	8,472
MO	Columbia	6		1,962	1,948
MO	Columbia	7		1,826	1,071
MO	Columbia	8		0	0
MO	Grand Avenue	—		—	—
MO	Hawthorn	5		6,870	6,884
MO	Iatan	1		14,263	16,467
MO	James River	3		5,243	4,506
MO	James River	4		5,628	4,297
MO	Jim Hill	—		—	—
MO	Lake Road	6		7,213	6,137
MO	Meramec	1		2,388	2,762
MO	Meramec	2		2,657	3,146
MO	Meramec	3		3,547	3
MO	Meramec	4		5,043	8,786
MO	Rush Island	1		35,767	27,562
MO	Rush Island	2		32,296	32,795
MO	Sibley	1		3,277	3,063
MO	Sibley	2		2,698	3,816
MO	Sikeston	1		8,196	7,746
MO	Southwest	1		5,876	4,348
MO	Thomas Hill	MB3		17,230	14,653
MT	Colstrip	1		7,825	7,289
MT	Colstrip	2		7,447	7,438
MT	Colstrip	3		2,702	2,596
MT	Colstrip	4		2,763	2,783
MT	Frank Bird	1		—	—
MT	JE Corette	2		6,484	6,720
MT	Lewis & Clark	B1		1,463	1,888
NE	Bluffs	4		0	—
NE	CW Burdick	B-3		0	0
NE	Canaday	1		374	263
NE	Gerald Gentleman Sta	1		9,634	10,445
NE	Gerald Gentleman Sta	2		9,406	11,702
NE	Harold Kramer	1		—	—
NE	Harold Kramer	2		—	—
NE	Harold Kramer	3		—	—
NE	Harold Kramer	4		—	—
NE	Hastings Energy Center	1		919	678
NE	Jones Street	26		—	—
NE	Jones Street	27		—	—
NE	Lon Wright	8		819	1,150
NE	Nebraska City	1		11,586	7,499
NE	North Omaha	1		1,095	978
NE	North Omaha	2		1,820	1,353
NE	North Omaha	3		2,035	1,709
NE	North Omaha	4		2,495	2,195
NE	North Omaha	5		2,787	2,788
NE	Platte	1		1,719	1,862
NE	Sheldon	1		2,660	1,973
NE	Sheldon	2		2,255	2,225
NV	Clark	1		25	186
NV	Clark	2		47	344
NV	Clark	3		0	0
NV	Fort Churchill	1		259	252
NV	Fort Churchill	2		753	272
NV	Mohave	1		24,527	22,039
NV	Mohave	2		24,792	20,488
NV	North Valmy	1		5,335	5,261
NV	North Valmy	2		1,624	1,835
NV	Reid Gardner	1		2,010	2,176
NV	Reid Gardner	2		2,154	2,035
NV	Reid Gardner	3		2,086	2,232
NV	Reid Gardner	4		2,860	3,340
NV	Sunrise	1		154	212
NV	Tracy	1		7	18
NV	Tracy	2		14	6
NV	Tracy	3		824	331
NH	Newington	1		23,307	25,328
NH	Schiller	4		2,775	2,909
NH	Schiller	5		2,480	2,442
NH	Schiller	6		2,596	2,532
NJ	BL England	3		2,442	3,380
NJ	Bergen	1		576	535
NJ	Bergen	2		521	332
NJ	Burlington	7		882	1,016

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
NJ	Deepwater	1		1,055	736
NJ	Deepwater	3		0	0
NJ	Deepwater	4		0	15
NJ	Deepwater	5		0	0
NJ	Deepwater	6		0	0
NJ	Deepwater	8		2,723	3,019
NJ	Deepwater	9		2,189	1,929
NJ	Gilbert	01		57	95
NJ	Gilbert	02		151	67
NJ	Gilbert	03		973	1,439
NJ	Gilbert	04		22	18
NJ	Gilbert	05		21	20
NJ	Gilbert	06		22	23
NJ	Gilbert	07		19	24
NJ	Hudson	1		178	176
NJ	Hudson	2		14,083	17,647
NJ	Kearny	7		126	204
NJ	Kearny	8		168	275
NJ	Linden	2		330	656
NJ	Linden	4		176	387
NJ	Linden	11		678	777
NJ	Linden	12		967	591
NJ	Linden	13		637	741
NJ	Mercer	1		9,197	9,899
NJ	Mercer	2		8,751	8,530
NJ	Sayreville	02		4	2
NJ	Sayreville	03		2	1
NJ	Sayreville	05		6	5
NJ	Sayreville	06		1	10
NJ	Sayreville	07		214	354
NJ	Sayreville	08		374	202
NJ	Sewaren	1		40	104
NJ	Sewaren	2		64	120
NJ	Sewaren	3		74	97
NJ	Sewaren	4		138	104
NJ	Sewaren	5		0	0
NJ	Werner	04		172	161
NM	Cunningham	121B		0	0
NM	Cunningham	122B		0	0
NM	Escalante	1		1,323	1,185
NM	Four Corners	1		3,289	3,341
NM	Four Corners	2		3,571	3,540
NM	Four Corners	3		4,390	4,630
NM	Four Corners	4		13,623	11,331
NM	Four Corners	5		13,623	13,452
NM	Maddox	051B		0	0
MN	North Lovington	S2		—	—
NM	Person	3		0	—
NM	Person	4		0	—
NM	Reeves	1		0	0
NM	Reeves	2		0	0
NM	Reeves	3		0	0
NM	Rio Grande	4		—	—
NM	Rio Grande	5		—	—
NM	Rio Grande	6		0	2
NM	Rio Grande	7		0	5
NM	Rio Grande	8		0	17
NM	San Juan	1		5,621	6,217
NM	San Juan	2		4,208	6,755
NM	San Juan	3		6,484	9,512
NM	San Juan	4		9,270	11,885
NY	59th Street	110		41	11
NY	59th Street	114		42	21
NY	59th Street	115		39	23
NY	74th Street	120		106	136
NY	74th Street	121		106	39
NY	74th Street	122		106	150
NY	Albany	1		3,261	1,145
NY	Albany	2		2,059	1,005
NY	Albany	3		2,316	584
NY	Albany	4		2,639	1,188
NY	Arthur Kill	20		1,626	1,543
NY	Arthur Kill	30		2,185	2,638
NY	Astoria	10		258	444
NY	Astoria	20		188	253
NY	Astoria	30		774	1,572
NY	Astoria	40		1,275	1,936

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
NY	Astoria	50		1,777	1,683
NY	Bowline Point	1		2,511	4,214
NY	Bowline Point	2		2,740	2,269
NY	CR Huntley	63		5,890	8,211
NY	CR Huntley	64		6,682	7,867
NY	CR Huntley	65		5,752	7,665
NY	CR Huntley	66		3,067	8,037
NY	CR Huntley	67		10,494	17,452
NY	CR Huntley	68		14,116	15,514
NY	Charles Poletti	001		2,482	894
NY	Danskammer	1		799	570
NY	Danskammer	2		946	601
NY	Danskammer	3		3,745	3,594
NY	Danskammer	4		6,040	6,737
NY	Dunkirk	1		10,291	11,429
NY	Dunkirk	2		9,251	11,325
NY	EF Barrett	10		592	283
NY	EF Barrett	20		874	842
NY	East River	50		743	673
NY	East River	60		438	519
NY	East River	70		113	373
NY	Far Rockaway	40		189	347
NY	Glenwood	40		342	486
NY	Glenwood	50		352	514
NY	Goudey	11		2,486	2,573
NY	Goudey	12		2,355	2,389
NY	Goudey	13		8,977	9,425
NY	Greenidge	4		2,630	8,450
NY	Greenidge	5		2,379	3,393
NY	Hickling	1		1,143	1,824
NY	Hickling	2		1,158	1,784
NY	Hickling	3		1,879	2,168
NY	Hickling	4		1,879	2,037
NY	Hudson Avenue	71		0	—
NY	Hudson Avenue	72		0	—
NY	Hudson Avenue	73		0	—
NY	Hudson Avenue	74		0	—
NY	Hudson Avenue	81		0	—
NY	Hudson Avenue	82		0	—
NY	Hudson Avenue	83		0	—
NY	Hudson Avenue	84		0	—
NY	Hudson Avenue	100		321	349
NY	Jennison	1		1,088	1,434
NY	Jennison	2		1,089	1,327
NY	Jennison	3		1,078	1,303
NY	Jennison	4		1,076	1,150
NY	Lovett	3		70	458
NY	Lovett	4		1,963	3,276
NY	Lovett	5		2,907	3,938
NY	Northport	4		8,076	8,036
NY	Oswego	1		0	0
NY	Oswego	2		0	0
NY	Oswego	3		0	0
NY	Oswego	4		16	799
NY	Oswego	5		20,905	20,052
NY	Oswego	6		8,957	7,914
NY	Port Jefferson	1		612	977
NY	Port Jefferson	2		631	941
NY	Ravenswood	10		495	403
NY	Ravenswood	20		507	513
NY	Ravenswood	30		2,900	3,069
NY	Rochester 3	1		—	—
NY	Rochester 3	2		—	—
NY	Rochester 3	3		—	—
NY	Rochester 3	4		—	—
NY	Rochester 3	7		—	—
NY	Rochester 3	8		—	—
NY	Rochester 3	12		7,007	8,139
NY	Rochester 7	1		3,122	4,514
NY	Rochester 7	2		5,265	6,477
NY	Rochester 7	3		4,678	6,263
NY	Rochester 7	4		5,620	7,731
NY	Roseton	1		16,513	23,594
NY	Roseton	2		21,496	22,464
NY	SA Carlson	9		4,313	3,212
NY	SA Carlson	10		0	0
NY	SA Carlson	11		0	0

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
NY	SA Carlson	12		0	0
NY	Somerset	1		13,819	14,439
NY	Waterside	41		3	0
NY	Waterside	42		3	0
NY	Waterside	51		13	57
NY	Waterside	52		12	57
NY	Waterside	61		21	59
NY	Waterside	62		27	67
NY	Waterside	80		67	103
NY	Waterside	90		72	116
NC	Asheville	1		7,031	9,696
NC	Asheville	2		9,022	11,566
NC	Belews Creek	1		33,395	32,867
NC	Belews Creek	2		46,690	42,584
NC	Buck	5		0	0
NC	Buck	6		0	0
NC	Buck	7		0	0
NC	Buck	8		0	0
NC	Buck	9		2,279	1,536
NC	Cape Fear	3		0	0
NC	Cape Fear	4		0	0
NC	Cape Fear	5		3,796	5,666
NC	Cape Fear	6		4,617	5,017
NC	Cliffside	1		0	0
NC	Cliffside	2		0	0
NC	Cliffside	3		0	0
NC	Cliffside	4		0	0
NC	Cliffside	5		12,716	14,190
NC	Dan River	1		872	186
NC	Dan River	2		833	133
NC	Dan River	3		1	1,080
NC	GG Allen	1		0	0
NC	GG Allen	2		0	1,123
NC	GG Allen	3		5,309	5,388
NC	GG Allen	4		4,397	5,694
NC	GG Allen	5		5,255	3,653
NC	LV Sutton	1		1,172	1,738
NC	LV Sutton	2		1,582	2,112
NC	LV Sutton	3		8,407	12,043
NC	Lee	1		912	1,465
NC	Lee	2		906	1,507
NC	Lee	3		5,208	5,582
NC	Marshall	1		11,682	12,384
NC	Marshall	2		11,671	9,344
NC	Marshall	3		9,326	21,254
NC	Marshall	4		13,851	21,941
NC	Mayo	1A		12,146	26,167
NC	Mayo	1B		12,146	0
NC	Riverbend	7		0	0
NC	Riverbend	8		2,238	1,642
NC	Riverbend	9		0	0
NC	Riverbend	10		0	0
NC	Roxboro	1		18,006	16,294
NC	Roxboro	2		18,903	22,980
NC	Roxboro	3A		14,978	28,489
NC	Roxboro	3B		14,978	0
NC	Roxboro	4A		11,589	22,112
NC	Roxboro	4B		11,589	0
NC	WH Weatherspoon	1		692	887
NC	WH Weatherspoon	2		643	1,141
NC	WH Weatherspoon	3		1,569	1,896
ND	Antelope Valley	B1		10,850	8,915
ND	Antelope Valley	B2		10,618	10,112
ND	Coal Creek	1		24,278	26,337
ND	Coal Creek	2		25,878	26,041
ND	Coyote	B1		16,903	16,221
ND	Leland Olds	1		0	4,326
ND	Leland Olds	2		26,803	16,991
ND	Milton R Young	B1		16,348	16,132
ND	Milton R Young	B2		18,100	18,403
ND	RM Heskett	B2		3,467	5,174
ND	Stanton	1		7,977	8,502
ND	Stanton	10		1,344	1,127
OH	Acme	9		0	0
OH	Acme	11		0	0
OH	Acme	13		0	0
OH	Acme	14		0	0

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
OH	Acme	15		0	1
OH	Acme	16		724	570
OH	Acme	91		511	427
OH	Acme	92		597	400
OH	Ashtabula	8		3,462	5,731
OH	Ashtabula	9		5,928	3,711
OH	Ashtabula	10		5,549	5,303
OH	Ashtabula	11		6,419	5,874
OH	Avon Lake	7		0	—
OH	Avon Lake	9		5,928	3,711
OH	Avon Lake	10		6,643	7,849
OH	Bay Shore	1		4,696	5,929
OH	Bay Shore	2		6,717	4,430
OH	Bay Shore	3		8,712	6,563
OH	Bay Shore	4		9,948	11,850
OH	Cardinal	3		24,252	23,306
OH	Conesville	5		10,809	10,291
OH	Conesville	6		11,467	9,528
OH	Edgewater	11		1,598	468
OH	Edgewater	12		1,647	650
OH	Edgewater	13		6,707	8,250
OH	Frank M Tait	4		—	—
OH	Frank M Tait	5		—	—
OH	Frank M Tait	7–1		—	—
OH	Frank M Tait	7–2		—	—
OH	Frank M Tait	8–1		—	—
OH	Frank M Tait	8–2		—	—
OH	Gorge	25		2,430	3,047
OH	Gorge	26		2,840	3,136
OH	Hamilton	9		904	975
OH	JM Stuart	1		51,470	48,767
OH	JM Stuart	2		48,730	43,413
OH	JM Stuart	3		44,608	46,814
OH	JM Stuart	4		50,348	47,393
OH	Killen Station	2		23,571	25,415
OH	Lake Road	6		—	—
OH	Lake Shore	18		8,330	4,342
OH	Lake Shore	91		286	354
	Lake Shore	92		272	403
OH	Lake Shore	93		280	363
OH	Lake Shore	94		388	861
OH	Miami Fort	6		17,335	15,712
OH	OH Hutchings	H–1		1,002	377
OH	OH Hutchings	H–2		606	322
OH	OH Hutchings	H–3		945	369
OH	OH Hutchings	H–4		933	267
OH	OH Hutchings	H–5		822	377
OH	OH Hutchings	H–6		953	561
OH	Poston	1		—	—
OH	Poston	2		—	—
OH	Poston	3		—	—
OH	Poston	4		—	—
OH	RE Burger	1		3,661	4,579
OH	RE Burger	2		3,625	4,578
OH	RE Burger	3		3,002	4,179
OH	RE Burger	4		3,439	4,221
OH	Refuse and Coal	001		1,313	1,207
OH	Refuse and Coal	002		1,417	1,152
OH	Refuse and Coal	003		1,077	1,131
OH	Refuse and Coal	004		1,152	1,234
OH	Refuse and Coal	005		1,161	646
OH	Refuse and Coal	006		1,289	894
OH	Tidd	-		—	—
OH	Toronto	9		5,094	6,332
OH	Toronto	10		9,502	9,664
OH	Toronto	11		10,184	10,562
OH	WH Sammis	1		6,263	8,547
OH	WH Sammis	2		8,860	7,898
OH	WH Sammis	3		8,771	7,646
OH	WH Sammis	4		7,746	8,113
OH	Walter C Beckjord	1		1,722	1,865
OH	Walter C Beckjord	2		1,652	1,927
OH	Walter C Beckjord	3		3,304	3,783
OH	Walter C Beckjord	4		3,421	3,647
OK	Anadarko	3		0	—
OK	Arbuckle	ARB		—	—
OK	Comanche	7251		0	0

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
OK	Comanche	7252		0	0
OK	GRDA	1		9,814	10,238
OK	GRDA	2		6,141	6,311
OK	Horseshoe Lake	6		15	5
OK	Horseshoe Lake	7		4	19
OK	Horseshoe Lake	8		0	0
OK	Hugo	1		14,923	12,017
OK	Mooreland	1		0	0
OK	Mooreland	2		0	0
OK	Mooreland	3		0	0
OK	Muskogee	3		0	1
OK	Muskogee	4		8,029	10,508
OK	Muskogee	5		8,505	8,954
OK	Muskogee	6		7,410	8,517
OK	Mustang	1		0	0
OK	Mustang	2		0	0
OK	Mustang	3		0	0
OK	Mustang	4		0	0
OK	Northeastern	3301		0	0
OK	Northeastern	3302		0	0
OK	Northeastern	3313		13,225	9,080
OK	Northeastern	3314		12,605	10,392
OK	Ponca	2		0	0
OK	Riverside	1501		0	0
OK	Riverside	1502		0	0
OK	Seminole	1		0	0
OK	Seminole	2		0	0
OK	Seminole	3		8	10
OK	Sooner	1		9,386	11,442
OK	Sooner	2		7,253	8,557
OK	Southwestern	801N		0	0
OK	Southwestern	801S		0	0
OK	Southwestern	8002		0	0
OK	Southwestern	8003		0	0
OK	Tulsa	1402		—	—
OK	Tulsa	1403		—	—
OK	Tulsa	1404		—	—
OR	Boardman	1SG		—	1,805
PA	Bruce Mansfield	1		14,146	14,536
PA	Bruce Mansfield	2		15,933	10,369
PA	Bruce Mansfield	3		14,526	14,798
PA	Cromby	1		3,115	3,223
PA	Cromby	2		2,283	2,971
PA	Delaware	71		877	989
PA	Delaware	81		673	828
PA	Eddystone	1		3,149	2,558
PA	Eddystone	2		2,598	3,115
PA	Eddystone	3		1,084	1,772
PA	Eddystone	4		1,808	1,572
PA	Elrama	1		813	1,425
PA	Elrama	2		797	1,443
PA	Elrama	3		1,455	1,521
PA	Elrama	4		3,185	3,147
PA	FR Phillips	1		—	—
PA	FR Phillips	2		—	—
PA	FR Phillips	3		—	—
PA	FR Phillips	4		—	—
PA	FR Phillips	5		—	—
PA	FR Phillips	6		—	—
PA	Front Street	9		3,845	4,725
PA	Front Street	10		4,069	4,399
PA	Holtwood	17		18,467	19,162
PA	Homer City	1		40,907	45,993
PA	Homer City	2		50,553	37,232
PA	Homer City	3		57,143	24,124
PA	Hunlock Power	6		2,458	2,862
PA	Keystone	1		75,460	64,742
PA	Keystone	2		61,655	73,498
PA	Martins Creek	3		2,045	1,124
PA	Martins Creek	4		1,985	1,551
PA	Mitchell	1		0	0
PA	Mitchell	2		0	0
PA	Mitchell	3		0	0
PA	Mitchell	33		4,756	4,404
PA	Montour	1		62,734	65,989
PA	Montour	2		62,701	63,215
PA	New Castle	1		1,092	951

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
PA	New Castle	2		1,771	1,208
PA	New Castle	3		5,931	6,419
PA	New Castle	4		5,743	7,295
PA	New Castle	5		7,170	10,933
PA	Richmond	63		—	—
PA	Richmond	64		—	—
PA	Schuylkill	1		550	627
PA	Schuylkill	23		—	—
PA	Schuylkill	24		—	—
PA	Schuylkill	26		—	—
PA	Seward	12		2,913	2,926
PA	Seward	14		3,000	2,905
PA	Seward	15		9,720	12,005
PA	Southwark	11		—	—
PA	Southwark	12		—	—
PA	Southwark	21		—	—
PA	Southwark	22		—	—
PA	Springdale	77		—	—
PA	Springdale	88		—	—
PA	Titus	1		5,182	4,859
PA	Titus	2		4,239	5,282
PA	Titus	3		4,453	4,434
PA	Warren	1		2,391	2,199
PA	Warren	2		2,134	2,351
PA	Warren	3		2,449	1,974
PA	Warren	4		2,175	1,999
RI	Manchester Street	6		854	750
RI	Manchester Street	7		639	507
RI	Manchester Street	12		821	465
RI	South Street	121		1,328	338
RI	South Street	122		1,087	339
SC	Canadys Steam	CAN1		4,716	4,664
SC	Canadys Steam	CAN2		4,432	4,668
SC	Canadys Steam	CAN3		5,974	5,162
SC	Cross	2		8,931	8,812
SC	Dolphus M Grainger	1		2,071	2,278
SC	Dolphus M Grainger	2		2,862	3,656
SC	HB Robinson	1		6,349	6,169
SC	Hagood	HAG1		-	0
SC	Hagood	HAG2		-	23
SC	Hagood	HAG3		-	0
SC	Jefferies	1		0	106
SC	Jefferies	2		13	127
SC	Jefferies	3		7,260	10,217
SC	Jefferies	4		5,831	8,475
SC	McMeekin	MCM1		5,513	7,786
SC	McMeekin	MCM2		7,996	5,047
SC	Urquhart	URQ1		3,006	3,678
SC	Urquhart	URQ2		2,648	3,271
SC	Urquhart	URQ3		4,248	5,502
SC	WS Lee	1		1,543	1,480
SC	WS Lee	2		1,402	1,320
SC	WS Lee	3		2,432	1,947
SC	Wateree	WAT1		19,303	17,900
SC	Wateree	WAT2		16,842	12,985
SC	Williams	WIL1		28,875	24,607
SC	Winyah	1		14,418	13,850
SC	Winyah	2		10,132	9,980
SC	Winyah	3		3,413	3,219
SC	Winyah	4		2,891	3,702
SD	Big Stone	1		29,363	27,725
SD	Pathfinder	11		0	0
SD	Pathfinder	12		0	0
SD	Pathfinder	13		0	0
TN	Bull Run	1		28,849	38,980
TN	John Sevier	1		14,021	16,202
TN	John Sevier	2		17,462	16,103
TN	John Sevier	3		13,260	16,451
TN	John Sevier	4		13,298	17,382
TN	Kingston	1		9,107	9,795
TN	Kingston	2		6,626	9,406
TN	Kingston	3		7,735	9,445
TN	Kingston	4		7,090	8,774
TN	Kingston	5		13,841	11,499
TN	Kingston	6		14,022	8,307
TN	Kingston	7		14,558	12,434
TN	Kingston	8		14,215	0

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
TN	Kingston	9		14,168	8,758
TN	Watts Bar	A		—	—
TN	Watts Bar	B		—	—
TN	Watts Bar	C		—	—
TN	Watts Bar	D		—	—
TX	Barney M Davis	1		2	21
TX	Barney M Davis	2		12	155
TX	Big Brown	1		28,204	28,801
TX	Big Brown	2		26,320	32,583
TX	Bryan	6		0	4
TX	CE Newman	BW5		—	—
TX	Cedar Bayou	CBY1		0	200
TX	Cedar Bayou	CBY2		0	145
TX	Cedar Bayou	CBY3		805	81
TX	Celanese	2		—	—
TX	Coleto Creek	1		14,741	13,433
TX	Collin	1		0	184
TX	Concho	2		0	0
TX	Concho	4		0	0
TX	Concho	5		0	0
TX	Concho	6		0	0
TX	Concho	7		1	0
TX	Dallas	3		2	55
TX	Dallas	9		15	46
TX	Dansby	1		1	5
TX	Decker Creek	1		0	2
TX	Decker Creek	2		0	5
TX	Decordova	1		106	329
TX	Deepwater	DWP1		—	—
TX	Deepwater	DWP2		—	—
TX	Deepwater	DWP3		—	—
TX	Deepwater	DWP4		—	—
TX	Deepwater	DWP5		—	—
TX	Deepwater	DWP6		—	—
TX	Deepwater	DWP7		—	—
TX	Deepwater	DWP8		—	—
TX	ES Joslin	1		1	3
TX	Eagle Mountain	1		14	95
TX	Eagle Mountain	2		23	71
TX	Eagle Mountain	3		0	0
TX	Fort Phantom	1		4	56
TX	Fort Phantom	2		0	28
TX	Gibbons Creek	1		20,272	20,329
TX	Graham	1		9	0
TX	Graham	2		1	32
TX	Greens Bayou	GBY1		—	—
TX	Greens Bayou	GBY2		—	—
TX	Greens Bayou	GBY3		—	—
TX	Greens Bayou	GBY4		—	—
TX	Greens Bayou	GBY5		9	69
TX	Handley	1A		0	0
TX	Handley	1B		0	0
TX	Handley	2		0	0
TX	Handley	3		4	123
TX	Handley	4		47	247
TX	Handley	5		41	315
TX	Harrington Station	061B		8,645	8,008
TX	Harrington Station	062B		9,332	9,006
TX	Harrington Station	063B		8,630	10,471
TX	Hiram Clarke	HOC1		—	—
TX	Hiram Clarke	HOC2		—	—
TX	Hiram Clarke	HOC3		—	—
TX	Hiram Clarke	HOC4		—	—
TX	Holly Ave	1		0	0
TX	Holly Ave	2		0	0
TX	Holly Street	1		0	2
TX	Holly Street	2		2	7
TX	Holly Street	3		0	9
TX	Holly Street	4		0	0
TX	JL Bates	1		0	0
TX	JL Bates	2		1	3
TX	JT Deely	1		9,753	10,900
TX	JT Deely	2		10,998	8,995
TX	Jones Station	151B		2	0
TX	Jones Station	152B		1	20
TX	Knox Lee	1		—	—
TX	Knox Lee	2		0	0

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
TX	Knox Lee	3		0	0
TX	Knox Lee	4		0	0
TX	Knox Lee	5		0	0
TX	La Palma	7		3	0
TX	Lake Creek	1		3	35
TX	Lake Creek	2		17	55
TX	Lake Hubbard	1		22	176
TX	Lake Hubbard	2		103	314
TX	Laredo	1		0	1
TX	Laredo	2		0	0
TX	Laredo	3		2	0
TX	Leon Creek	1		0	—
TX	Leon Creek	2		0	—
TX	Leon Creek	3		0	0
TX	Leon Creek	4		0	0
TX	Lewis Creek	1		0	0
TX	Lewis Creek	2		0	0
TX	Limestone	LIM1		14,785	16,431
TX	Limestone	LIM2		15,045	15,326
TX	Lon C Hill	1		0	0
TX	Lon C Hill	2		0	0
TX	Lon C Hill	3		0	1
TX	Lon C Hill	4		0	2
TX	Lone Star	1		0	0
TX	Martin Lake	1		34,774	36,225
TX	Martin Lake	2		33,054	34,545
TX	Martin Lake	3		34,165	34,513
TX	Mission Road	3		0	0
TX	Monticello	1		25,171	29,453
TX	Monticello	2		27,191	29,892
TX	Monticello	3		30,901	32,982
TX	Morgan Creek	3		0	0
TX	Morgan Creek	4		0	2
TX	Morgan Creek	5		0	36
TX	Morgan Creek	6		9	248
TX	Mountain Creek	2		0	10
TX	Mountain Creek	3A		1	21
TX	Mountain Creek	3B		1	0
TX	Mountain Creek	6		0	49
TX	Mountain Creek	7		9	38
TX	Mountain Creek	8		63	293
TX	Neches	11		—	—
TX	Neches	13		—	—
TX	Neches	15		—	—
TX	Neches	18		—	—
TX	Newman	1		0	6
TX	Newman	2		0	0
TX	Newman	3		0	0
TX	Nichols Station	141B		0	0
TX	Nichols Station	142B		0	0
TX	Nichols Station	143B		0	0
TX	North Lake	1		37	169
TX	North Lake	2		26	262
TX	North Lake	3		64	213
TX	North Main	4		11	32
TX	North Texas	3		0	19
TX	Nueces Bay	5		0	0
TX	Nueces Bay	6		0	2
TX	Nueces Bay	7		2	21
TX	OW Sommers	1		0	23
TX	OW Sommers	2		0	40
TX	Oak Creek	1		0	22
TX	Oklaunion	1		4,643	5,387
TX	PH Robinson	PHR1		0	0
TX	PH Robinson	PHR2		0	0
TX	PH Robinson	PHR3		0	0
TX	PH Robinson	PHR4		6	179
TX	Paint Creek	1		1	16
TX	Paint Creek	2		0	17
TX	Paint Creek	3		0	35
TX	Paint Creek	4		0	12
TX	Parkdale	1		8	54
TX	Parkdale	2		7	63
TX	Parkdale	3		56	75
TX	Permian Basin	5		0	0
TX	Permian Basin	6		83	228
TX	Pirkey	1		21,583	23,101

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
TX	Plant X	111B		0	0
TX	Plant X	112B		0	0
TX	Plant X	113B		0	0
TX	Plant X	114B		1	0
TX	Powerlane	2		0	0
TX	Powerlane	3		0	0
TX	RW Miller	1		0	0
TX	RW Miller	2		0	26
TX	RW Miller	3		0	79
TX	Ray Olinger	BW2		0	0
TX	Ray Olinger	BW3		0	6
TX	Ray Olinger	CE1		0	0
TX	Rio Pecos	5		0	0
TX	Rio Pecos	6		0	7
TX	River Crest	1		3	41
TX	Sabine	1		0	0
TX	Sabine	2		0	0
TX	Sabine	3		0	0
TX	Sabine	4		1	0
TX	Sabine	5		32	10
TX	Sam Bertron	SRB1		0	1
TX	Sam Bertron	SRB2		0	2
TX	Sam Bertron	SRB3		46	9
TX	Sam Bertron	SRB4		1	6
TX	Sam Seymour	1		12,601	9,778
TX	Sam Seymour	2		12,820	11,083
TX	Sam Seymour	3		3,635	4,292
TX	San Angelo	2		0	14
TX	San Miguel	SM-1		18,924	19,727
TX	Sandow	4		27,494	26,513
TX	Seaholm	9		0	0
TX	Sim Gideon	1		0	16
TX	Sim Gideon	2		0	44
TX	Sim Gideon	3		0	29
TX	Spencer	4		0	7
TX	Spencer	5		0	5
TX	Stryker Creek	1		4	25
TX	Stryker Creek	2		6	181
TX	TC Ferguson	1		0	0
TX	TH Wharton	THW1		—	—
TX	TH Wharton	THW2		0	3
TX	TNP One	U1		—	0
TX	Tolk Station	171B		11,282	15,213
TX	Tolk Station	172B		12,078	13,695
TX	Tradinghouse	1		30	150
TX	Tradinghouse	2		11	251
TX	Trinidad	7		25	21
TX	Trinidad	8		0	0
TX	Trinidad	9		4	36
TX	VH Braunig	1		0	8
TX	VH Braunig	2		0	25
TX	VH Braunig	3		0	76
TX	Valley	1		10	32
TX	Valley	2		69	272
TX	Valley	3		0	0
TX	Victoria	5		—	—
TX	Victoria	6		0	0
TX	Victoria	7		0	0
TX	Victoria	8		1	5
TX	WA Parish	WAP1		0	5
TX	WA Parish	WAP2		0	3
TX	WA Parish	WAP3		0	0
TX	WA Parish	WAP4		0	0
TX	WA Parish	WAP5		13,012	18,768
TX	WA Parish	WAP6		17,263	19,460
TX	WA Parish	WAP7		9,913	12,951
TX	WA Parish	WAP8		6,512	5,450
TX	WB Tuttle	1		0	0
TX	WB Tuttle	2		0	0
TX	WB Tuttle	3		0	0
TX	WB Tuttle	4		0	0
TX	Webster	WEB1		—	—
TX	Webster	WEB2		—	—
TX	Webster	WEB3		0	0
TX	Welsh	1		10,415	10,723
TX	Welsh	2		10,279	10,219
TX	Welsh	3		9,572	10,190

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
TX	Wilkes	1		0	0
TX	Wilkes	2		0	0
TX	Wilkes	3		0	0
UT	Bonanza	1-1		700	764
UT	Carbon	1		1,469	2,659
UT	Carbon	2		2,853	3,186
UT	Gadsby	1		—	—
UT	Gadsby	2		—	—
UT	Gadsby	3		—	—
UT	Hale	1		—	—
UT	Hunter (Emery)	1		2,511	2,332
UT	Hunter (Emery)	2		2,146	2,308
UT	Hunter (Emery)	3		1,253	1,160
UT	Huntington	1		11,208	11,450
UT	Huntington	2		8,704	11,591
UT	Intermountain	1SGA		4,454	3,779
UT	Intermountain	2SGA		3,660	4,596
VT	J C McNeil	1		4	14
VA	Bremo Bluff	3		2,574	2,587
VA	Bremo Bluff	4		5,028	6,611
VA	Chesapeake	1		4,565	6,466
VA	Chesapeake	2		4,438	6,489
VA	Chesapeake	3		8,131	7,584
VA	Chesapeake	4		10,073	11,829
VA	Chesterfield	3		3,471	3,367
VA	Chesterfield	4		7,648	6,963
VA	Chesterfield	5		15,482	14,628
VA	Chesterfield	6		20,931	25,748
VA	Clinch River	1		6,247	8,260
VA	Clinch River	2		6,477	7,386
VA	Clinch River	3		7,155	7,309
VA	Glen Lyn	6		5,563	7,087
VA	Glen Lyn	51		1,197	2,040
VA	Glen Lyn	52		-	-
VA	Possum Point	1		0	165
VA	Possum Point	2		0	510
VA	Possum Point	3		2,810	3,202
VA	Possum Point	4		7,789	9,090
VA	Possum Point	5		4,521	7,865
VA	Potomac River	1		1,565	2,694
VA	Potomac River	2		1,547	2,806
VA	Potomac River	3		3,968	3,494
VA	Potomac River	4		3,208	4,157
VA	Potomac River	5		4,017	3,916
VA	Yorktown	1		8,662	9,318
VA	Yorktown	2		8,660	8,706
VA	Yorktown	3		7,107	8,489
WA	Centralia	BW21		29,334	31,076
WA	Centralia	BW22		32,722	31,186
WA	Kettle Falls	1		0	0
WA	Shuffletown	1		-	303
WA	Shuffletown	2		-	261
WA	Shuffletown	3		-	303
WV	Albright	1		7,828	7,440
WV	Albright	2		7,962	7,497
WV	John E Amos	1		27,287	22,625
WV	John E Amos	2		22,226	25,387
WV	John E Amos	3		35,353	37,896
WV	Kanawha River	1		5,757	4,547
WV	Kanawha River	2		5,797	4,548
WV	Mountaineer	1		33,984	40,064
WV	Phil Sporn	11		3,017	5,814
WV	Phil Sporn	21		5,888	4,393
WV	Phil Sporn	31		3,628	5,936
WV	Phil Sporn	41		3,418	6,334
WV	Phil Sporn	51		14,006	17,916
WV	Pleasants	1		18,233	22,977
WV	Pleasants	2		20,851	24,139
WV	Rivesville	7		1,785	1,520
WV	Rivesville	8		2,832	3,896
WV	Willow Island	1		2,859	2,267
WV	Willow Island	2		12,004	11,004
WI	Alma	B4		2,188	2,383
WI	Alma	B5		2,890	3,365
WI	Bay Front	1		1,845	2,009
WI	Bay Front	2		0	0
WI	Bay Front	3		0	0

APPENDIX B TO PART 72—EXISTING PHASE II AFFECTED UNITS—Continued

State	Plant name	Unit	Basic allowance allocations (tons)	88 SO_2 (TPY)	89 SO_2 (TPY)
WI	Bay Front	4		0	0
WI	Bay Front	5		0	0
WI	Blount Street	3		0	2
WI	Blount Street	5		0	0
WI	Blount Street	6		0	0
WI	Blount Street	7		648	390
WI	Blount Street	8		2,693	2,124
WI	Blount Street	9		3,287	2,782
WI	Blount Street	11		0	0
WI	Columbia	1		21,082	17,638
WI	Columbia	2		6,887	10,615
WI	Commerce	25		–	–
WI	Edgewater	2		–	–
WI	Edgewater	3		5,641	3,476
WI	Edgewater	5		7,216	5,801
WI	J P Madgett	B1		6,939	7,282
WI	Manitowac	6		563	679
WI	Manitowac	7		697	0
WI	Pleasant Prairie	1		12,610	14,781
WI	Pleasant Prairie	2		13,598	15,886
WI	Port Washington	1		802	651
WI	Port Washington	2		2,358	1,431
WI	Port Washington	3		1,920	2,019
WI	Port Washington	4		1,700	1,563
WI	Port Washington	5		0	0
WI	Pulliam	3		1,261	753
WI	Pulliam	4		1,373	687
WI	Pulliam	5		3,632	2,304
WI	Pulliam	6		5,411	4,032
WI	Pulliam	7		10,248	7,170
WI	Rock River	1		2,977	4,155
WI	Rock River	2		3,207	2,612
WI	Stoneman	B1		324	371
WI	Stoneman	B2		324	373
WI	Valley	1		2,931	2,923
WI	Valley	2		3,420	3,077
WI	Valley	3		3,185	3,914
WI	Valley	4		3,319	2,380
WI	Weston	1		2,414	2,366
WI	Weston	2		4,442	4,394
WI	Weston	3		7,166	7,351
WY	Dave Johnston	BW41		4,203	3,631
WY	Dave Johnston	BW42		3,908	3,755
WY	Dave Johnston	BW43		8,266	7,625
WY	Dave Johnston	BW44		4,781	4,058
WY	Jim Bridger	BW71		5,736	5,682
WY	Jim Bridger	BW72		5,588	5,011
WY	Jim Bridger	BW73		5,214	5,748
WY	Jim Bridger	BW74		3,770	3,528
WY	Laramie River	1		4,175	2,643
WY	Laramie River	2		3,571	3,897
WY	Laramie River	3		3,855	3,361
WY	Naughton	1		10,162	8,993
WY	Naughton	2		11,300	13,335
WY	Naughton	3		5,054	5,248
WY	Wyodak	BW91		7,091	5,612

Appendix C to Part 72—Acid Rain Permit Program Forms

Phase I Acid Rain Permit Program Forms Instructions Package

Program Information

- Introduction.
- Table of Contents.
- General Instructions.
- Glossary (to be added).

Forms and Instructions

- Certificate of Representation Forms 7220 and 7220A.
- Acid Rain Phase I Permit Application Forms 7231 and 7231A.
- Substitution Plan Form 7241.
- Phase I Extension Early Ranking Application Form 7242.
- Phase I Extension Plan Form 7242A.
- Reduced Utilization Plan Form 7243.
- Reduced Utilization Plan Verification Form 7243A.
- NO_x Emissions Averaging Plan Form 7246 *
- NO_x Alternative Emissions Limitation Proposal Forms 7247 and 7247A *.
- NO_x Deadline Extension Forms 7248 *.
- Annual Compliance Certification Report Form 72402.

*These forms will be included in Part 76 Regulation.

• Utilization Report Form 72409.
• Forced Outage Report Form 72409A.
• Excess Emissions Offset Planning Form 772 (Part 77).
• Excess Emissions Penalty Forms 774 and 774A (Part 77).
• Phase I Acid Rain Permit Form 7251 (from 40 CFR § 72.51).

BILLING CODE 6560-50-M

PHASE I ACID RAIN PERMIT PROGRAM
INTRODUCTION and TABLE OF CONTENTS

I. INTRODUCTION: THE ACID RAIN PROGRAM

A. General Statutory Background on Acid Rain Regulation

The Clean Air Act Amendments of 1990 include Title IV, Acid Deposition Control. The purpose of this title is to reduce acid deposition (or "Acid Rain") by reducing annual emissions of sulfur dioxide and nitrogen oxides. This new law will achieve these reductions by requiring affected sources to meet prescribed emission limitations by specified deadlines. These sources can meet these limits through various Acid Rain compliance options that are made possible by an emission allocation and transfer system.

The Acid Rain Program is being implemented in two Phases. In Phase I (January 1, 1995 - December 31, 1999), the program will regulate 110 sources that include 261 utility units. These sources and units are listed in Appendix A of 40 CFR Part 72, and are referred to as "Appendix A units." These sources may choose to take advantage of compliance options that allow emissions transfers and allocations between and among the Appendix A units and certain other units, ("non-Appendix A units"). A non-Appendix A unit that is included in such a compliance option may become an "affected unit" that is regulated also in Phase I. Phase II begins on January 1, 2000, and after this date the Acid Rain Program will regulate all remaining existing utility units that emit SO_2 and NO_x, any new units, and any non-utility units that choose to "opt-in" to the program.

The compliance options available in Phase I are as follows:

(1) **Reduced Utilization**: Clean Air Act Section 408(c)(1)(b) and the regulations implementing that section at 40 CFR § 72.43, require that a unit file a reduced utilization plan if the unit will meet its emission reduction requirements through reduced utilization. If the projected utilization figures listed in the unit permit application are below the baseline figures listed, then the unit must file a plan. A unit also may file a reduced utilization plan to be activated during the permit term in the event that reduced utilization becomes a necessary or desirable compliance option. A more complete description of this provision and of the components of this plan are provided in the instructions for form #[7243].

(2) **Substitution Plan**: Clean Air Act Section 404(b) and the regulations implementing that part at 40 CFR § 72.41 allow an Appendix A unit to propose a reassignment of the sulfur dioxide emission reduction requirement at the unit to non-Appendix A "substitute" units that are under the control of the original unit's Designated Representative. A more complete description of this provision and of the components of a substitution plan are provided in the instructions for form #[7241].

(3) **Phase I Extension Plan**: Clean Air Act Section 404(d) and the regulations implementing that section at 40 CFR § 72.42 allow a unit to petition for an extension of its Phase I sulfur dioxide emissions limitation requirement. To qualify for such an extension, the unit must either employ a qualifying Phase I technology (see glossary) or transfer its Phase I emissions reduction obligation to a unit employing a qualifying Phase I technology. A more complete description of this provision and of the components of a Phase I extension plan are provided in the instructions for form #[7242].

Opt-in units and certain new units also will be regulated in Phase I. For a more complete description of who must apply for a Phase I permit, see Part III, General Instructions, Section A, "Who Must Apply," below.

B. Permit Program and Standard Forms

The EPA is charged with the responsibility of administering a permit program that will implement the Phase I requirements of the Acid Rain title. EPA will take applications, write and issue permits, monitor compliance and take appropriate enforcement action. The regulations that govern the Acid Rain Permit Program including the implementation of Phase I, are found at 40 CFR Part 72. The deadlines stated in this application are derived from Title IV of the Act and from the regulations. You should read them carefully.

The Agency has designed Acid Rain Program permit application forms to enable affected sources to apply for an Acid Rain permit that includes any of the optional compliance plans. This forms package contains all the forms you will need to submit a timely and complete application, and also contains forms for annual compliance certification and excess emissions reporting.

II. TABLE OF CONTENTS FOR INSTRUCTIONS PACKAGE

* These forms will be included in the Part 76 regulations.

PHASE I ACID RAIN PERMIT PROGRAM
GENERAL INSTRUCTIONS

III. GENERAL INSTRUCTIONS

A. Who Must Apply

The regulations governing the Acid Rain Program require that the following stationary sources apply for a Phase I Acid Rain permit.

- Each source that includes an affected unit listed in Appendix A
- Each source that includes a unit not listed in Appendix A that is designated as an "affected unit" as follows:
  - A substitute unit designated in a substitution plan;
  - A compensating unit designated in a reduced utilization plan;
  - Each source that elects to become an affected source pursuant to Part 74.

Affected sources and affected units may not be exempted from the permitting requirements of the Acid Rain Program.

The individual responsible for submission of the Acid Rain permit application is the **Designated Representative** for the source that includes an affected unit or proposed affected unit. The Designated Representative is the "responsible official" for a source in the context of the Acid Rain Program, and must be approved by EPA pursuant to a certification process that establishes the authority of the Designated Representative to represent all units under his or her control. The certification of the Designated Representative is a prerequisite to EPA issuance of an Acid Rain permit or acceptance of allowance transactions.

The Designated Representative is required to certify (by signing the form) to the truth, accuracy and completeness of each form that he or she submits. The Designated Representative, the owner, and operators of the unit are liable for all violations of the Acid Rain law and regulations, and these certifications reiterate the obligations of all the responsible parties for compliance with the Acid Rain Program.

The proposed Designated Representative must apply for EPA approval of the certification by submitting Certificate of Representation Forms SF#[7220] for each affected source and SF#[7220A] for each affected unit at the source. See the instructions for those forms at pp. ____ for more information.

The **Reduced Utilization Plan** and the **Phase I Extension Plan** are multi-unit plans that can involve sources with different Designated Representatives. When submitting such plans, each Designated Representative must sign a proposed compliance option form and submit a copy with the permit application for each source involved. For the other multi-unit plans, **Substitution or NO_x Averaging**, all units and sources involved must be represented by the same Designated Representative.

B. When to File

- The Certificate of Representation forms must be postmarked no later than midnight **February 15, 1993**. To expedite allowance trading and permit processing, we suggest you submit these forms as early as possible.
- Phase I permit applications including proposed compliance plans must be postmarked no later than midnight, **February 15, 1993**.
- If possible, Acid Rain Program compliance option forms should be submitted with the permit application. If you submit a compliance option form after the permit application has been processed, a permit revision may be necessary. Because some compliance options have specific deadlines, a comprehensive list of the final date on which each form may be submitted is provided in Figure 1, below.

FIGURE 1: ACID RAIN COMPLIANCE OPTION FILING DEADLINES

Form Number	Compliance Option Form Name	Deadline
7241	Substitution Plan	**Any time during Phase I**, as a permit revision
7242	Phase I Extension Early Ranking Plan	
7242A	Phase I Extension Plan	
7243	Reduced Utilization Plan	**Any time during Phase I**, as a permit revision
7246	NO_x Emissions Averaging Plan	**Any time during Phase I or Phase II**, as a permit revision
7247	NO_x Alternative Emissions Limitation Proposal	**Any time during Phase I or Phase II**, as a permit revision
7247A	NO_x Alternative Emissions Limitation Proposal	no later than **90 days** before end of demonstration period
7248	NO_x Deadline Extension	**December 31, 1994**

EPA Form xxxx

GENERAL INSTRUCTIONS (continued)

C. Where to File

Send your Phase I Acid Rain Certificate of Representation Forms to EPA headquarters, addressed to the **Chief, Permits and Technologies Section**, Acid Rain Division (ANR-445), Office of Atmospheric and Indoor Air Programs, U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460. Send all other Acid Rain permit forms to the Appropriate Regional Office (see Figure 2, below) with copies to EPA Headquarters. Send a copy of all forms to the appropriate State air pollution agency (list on page 4).

FIGURE 2: EPA REGIONAL OFFICES

Region #	States Included	Address
Region I	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont	Director, Air, Pesticides and Toxics Management Division U. S. Environmental Protection Agency John F. Kennedy Federal Building Boston, Massachusetts, 02203
Region II	New Jersey, New York, Puerto Rico, Virgin Islands	Director, Air and Waste Management Division U. S. Environmental Protection Agency Federal Office Building 26 Federal Plaza (Foley Square) New York, New York 10278
Region III	Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia	Director, Air and Waste Management Division U. S. Environmental Protection Agency Curtis Buildings Sixth and Walnut Streets Philadelphia, Pennsylvania 19106
Region IV	Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee	Director, Air and Waste Management Division U. S. Environmental Protection Agency 345 Courtland Street, N.E. Atlanta, Georgia 30365
Region V	Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin	Director, Air Management Division U. S. Environmental Protection Agency 230 South Dearborn Street Chicago, Illinois 60604
Region VI	Arkansas, Louisiana, New Mexico, Oklahoma, Texas	Director, Air Pesticides, and Toxics Division U. S. Environmental Protection Agency 1445 Ross Avenue Dallas, Texas 75202
Region VII	Iowa, Kansas, Missouri, Nebraska	Director, Air and Waste Management Division U. S. Environmental Protection Agency 726 Minnesota Avenue Kansas City, Missouri 66101
Region VIII	Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming	Director, Air and Waste Management Division U. S. Environmental Protection Agency 1860 Lincoln Street Denver, Colorado 80295
Region IX	Arizona, California, Guam, Hawaii, Nevada	Director, Air and Waste Management Division U. S. Environmental Protection Agency 215 Fremont Street San Francisco, California 94105
Region X	Alaska, Oregon, Idaho, Washington	Director, Air and Waste Management Division U. S. Environmental Protection Agency 1200 Sixth Avenue Seattle, Washington 98101

PHASE I ACID RAIN PERMIT PROGRAM
GENERAL INSTRUCTIONS (continued)

State Air Pollution Agencies

State of **Alabama**, Air Pollution Control Division, 645 S. McDonough Street, Montgomery, Alabama 36104.

State of **Arizona**, Department of Health Services, 1740 West Adams Street, Phoenix, Arizona 85007.

State of **Arkansas**, Division of Air Pollution Control, Department of Pollution Control and Ecology, 8001 National Drive, P.O. Box 9583, Little Rock, Arkansas 72209.

State of **California**, Air Resources Board, 1102 Q Street, Sacramento, California 95814.

State of **Colorado**, Department of Health, Air Pollution Control Division, 4210 East llth Avenue, Denver, Colorado 80220.

State of **Connecticut**, Department of Environmental Protection, State Office Building, Hartford, Connecticut 06115.

State of **Delaware**, Delaware Department of Natural Resources and Environmental Control, 89 Kings Highway, P.O. Box 1401, Dover, Delaware 19901.

District of Columbia, Department of Consumer and Regulatory Affairs, 5000 Overlook Avenue S.W., Washington D.C. 20032.

State of **Florida**, Bureau of Air Quality Management, Department of Environmental Regulation, Twin Towers Office Building, 2600 Blair Stone Road, Tallahassee, Florida 32301.

State of **Georgia**, Environmental Protection Division, Department of Natural Resources, 205 Butler Street, S.E., East Tower, Atlanta, Georgia 30334.

State of **Idaho**, Department of Health and Welfare, Statehouse, Boise, Idaho 83701.

State of **Illinois**, Division of Air Pollution Control, 2200 Churchill Road, Springfield, Illinois 62706.

State of **Indiana**, Indiana Department of Environmental Management, 105 South Meridian Street, P.O. Box 6015, Indianapolis, Indiana 46206

State of **Iowa**, Iowa Department of Water, Air, and Waste Management, Henry A. Wallace Building, 900 East Grand, Des Moines, Iowa 50319.

State of **Kansas**, Kansas Department of Health and Environment, Bureau of Air Quality and Radiation Control, Forbes Field, Topeka, Kansas 66620.

State of **Kentucky**, Division of Air Pollution Control, Department for Natural Resources and Environmental Protection, U.S. 127, Frankfort, Kentucky 40601.

State of **Louisiana**, Program Administrator, Air Quality Division, Louisiana Department of Environmental Quality, P.O. Box 44096, Baton Rouge, Louisiana 70804.

State of **Maine**, Department of Environmental Protection, State House, Augusta, Maine 04330.

State of **Maryland**, Air Management Administration, Maryland Department of the Environment, 2500 Broening Highway, Baltimore, Maryland 21224.

Commonwealth of **Massachusetts**, Massachusetts Department of Environmental Quality Engineering, Division of Air Quality Control, One Winter Street, Boston, Massachusetts 02108.

State of **Michigan**, Air Pollution Control Division, Michigan Department of Natural Resources, Stevens T. Mason Building, 8th Floor, Lansing, Michigan 48926.

State of **Minnesota**, Minnesota Pollution Control Agency, Division of Air Quality, 520 Lafayette Road, St. Paul, Minnesota 55155.

State of **Mississippi**, Bureau of Pollution Control, Department of Natural Resources, P.O. Box 10385, Jackson, Mississippi 39209.

State of **Missouri**, Department of Natural Resources, P.O. Box 1368, Jefferson City, Missouri 65101.

State of **Montana**, Department of Health and Environmental Services, Cogswell Building, Helena, Montana 59601.

State of **Nebraska**, Department of Environmental Control, P.O. Box 94877, State House Station, Lincoln, Nebraska 68502.

State of **Nevada**, Department of Conservation and Natural Resources, Division of Environmental Protection, 201 South Fall Street, Carson City, Nevada 89710.

State of **New Hampshire**, New Hampshire Air Resources Agency, Health and Welfare Building, Hazen Drive, Concord, New Hampshire 03301.

State of **New Jersey**, Department of Environmental Protection, Division of Environmental Quality, Enforcement Element, John Fitch Plaza, CN-027, Trenton, New Jersey 08625.

State of **New Mexico**, Director, New Mexico Environmental Improvement Division, Health and Environmental Department, 1190 St. Francis Drive, Santa Fe, New Mexico 87503.

State of **New York**, Department of Environmental Conservation, Division of Air Resources, 50 Wolf Road, New York, New York 12233.

State of **North Carolina**, Environmental Management Commission, Department of Natural and Economic Resources, Division of Environmental Management, Attention: Air Quality Section, P.O. Box 27687, Raleigh, North Carolina 27611.

State of **North Dakota**, State Department of Health and Consolidated Laboratories, Division of Environmental Engineering, State Capitol, Bismark, North Dakota 58501.

State of **Ohio**, Ohio Environmental Protection Agency, 1800 Watermark Drive, Box 1049, Columbus Ohio 43266-0149.

State of **Oklahoma**, Oklahoma State Department of Health, Air Quality Service, P.O. Box 53551, Oklahoma City, Oklahoma 73152.

State of **Oregon**, Department of Environmental Quality, Yeon Building, 522 S.W. Fifth, Portland, Oregon 97204.

Commonwealth of **Pennsylvania**, Department of Environmental Resources, 105 S. Second Street, P.O. BOX 2357, Harrisburg, Pennsylvania 17120.

State of **Rhode Island**, Department of Environmental Management, 204 Cannon Building, Davis Street, Providence, Rhode Island 02908.

State of **South Carolina**, Office of Environmental Quality Control, Department of Health and Environmental Control, 2600 Bull Street, Columbia, South Carolina 29201.

State of **Tennessee**, Department of Public Health, Division of Air Pollution Control, 256 Capitol Hill Building, Nashville, Tennessee 37219.

State of **Texas**, Air Pollution Control Board, 6330 Highway 290 East, Austin, Texas 78723.

State of **Utah**, Department of Health, Bureau of Air Quality, 288 North 1460 West, P.O. Box 16690, Salt Lake City, Utah 841160690.

State of **Vermont**, Vermont Agency of Environmental Conservation, Air Pollution Control, State Office Building, Montpelier, Vermont 05602.

Commonwealth of **Virginia**, Virginia State Air Pollution Board, Room 1106, Ninth Street Office Building, Richmond, Virginia 23219.

State of **Washington**, Department of Ecology, Olympia, Washington 98504.

State of **West Virginia**, Air Pollution Control Commission, 1558 Washington Street East, Charleston, West Virginia 25311.

State of **Wisconsin**, Department of Natural Resources, P.O. Box 7921, Madison, Wisconsin 53707

EPA Form xxxx

PHASE I ACID RAIN PERMIT PROGRAM
GENERAL INSTRUCTIONS (continued)

D. Fees

During the years 1995 through 1999, EPA will not collect any operating permit fee with respect to emissions from any Phase I affected units, and States will not collect any permit fee with respect to Phase I Acid Rain permitting from any Phase I affected units.

Nothing in this section precludes States from collecting fees from sources that are not affected in Phase I.

E. Information Available to the Public

Information contained in these application forms upon request will be made available to the public for inspection and copying. However, you may request confidential treatment for certain information that you submit on certain supplementary forms. The specific instructions for each supplementary form state what information on the form, if any, may be claimed as confidential and what procedures govern the claim. No information on Forms ___ through ___ may be claimed as confidential.

F. Completion of Forms

(1) **Technical Form Completion Guidance:** Please type or print in the unshaded areas only. Some items have small graduation marks in the fill-in spaces. These marks indicate the number of characters that may be entered into our data system. The marks are spaced at 1/6" intervals and accommodate elite type (12 characters per inch). If you use another type you may ignore the marks, but the number of characters should not exceed the number of spaces provided.

If you print, place each character between the marks. Abbreviate if necessary to stay within the number of characters allowed for each item. Use one space for breaks between words, but not for punctuation marks unless they are needed to clarify your response.

"Mark" all appropriate check boxes with an "X" rather than a "✓"

(2) **Completeness Requirements:** Unless otherwise specified in instructions to the forms, each item in each form must be answered. To indicate that each item has been considered, enter "NA" for "not applicable" if a particular item does not fit the circumstances or characteristics of your facility or activity.

Even if you have previously submitted requested information to EPA or to an approved State agency, you must repeat the information in the space provided, unless the form and instructions indicate that a reference to prior submissions will suffice.

(3) **Paperwork Reduction Act Notification:** The time needed to complete and file the forms included in this package will vary depending on individual circumstances. The estimated times are listed in Figure 3, below.

Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing the burden, to **Chief, Information Policy Branch**, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, DC 20460; and to **Paperwork Reduction Project** (OMB 20xx-xxxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503.

FIGURE 3: PAPERWORK BURDEN ESTIMATES FOR ACID RAIN PERMIT FORMS

Form		Preparing the Form	Copying, Assembling and Sending the Form
Number	Name		
7220 and 7220A	Designated Representative Certification		
7231 and 7231A	Acid Rain Phase I Permit Application		
7241	Substitution Plan		
7242 and 7242A	Phase I Extension Plan		
7243 and 7243A	Reduced Utilization Plan/End of Year Report		
7246	NO_x Emissions Averaging Plan		
7247	NO_x Alternative Emissions Proposal		
7247A	NO_x Alternative Emissions: Final Alternative Limit		
7248	NO_x Deadline Extension		
72402	Annual Compliance Certification Report		
72409 and 72409A	Utilization/Forced Outage Reports		
772	Excess Emissions Offset Planning		
774 and 774A	Excess Emissions Penalty		

GLOSSARY OF ACID RAIN PROGRAM TERMS

GLOSSARY OF ACID RAIN PROGRAM TERMS

[to be added]

EPA Form xxxx

FORMS 7220 AND 7220A

Certificate of Representation

Form 7220

Certificate of Representation (Single Source)

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average ____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

Form 7220A

Certificate of Representation (Individual Unit Information)

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average ____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

DRAFT 7220
Date 10/21/91
Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Certificate of Representation (Single Source)

Follow instructions for Form 7220.

I. DESIGNATED REPRESENTATIVE IDENTIFICATION

Designated Representative

A. Last Name
B. First Name
C. MI
D. Street or P.O. Box
E. City
F. State
G. Zip
H. Phone *(area code & number)*
I. Facsimile *(area code & number)*

FOR EPA USE ONLY

Designated Representative Identification Number

Alternate Designated Representative

A. Last Name
B. First Name
C. MI
D. Street or P.O. Box
E. City
F. State
G. Zip
H. Phone *(area code & number)*
I. Facsimile *(area code & number)*

FOR EPA USE ONLY

Alternate Designated Representative Identification Number

II. SOURCE IDENTIFICATION

A. Source Name
B. Street or P.O. Box
C. City
D. State
E. Zip

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

Please type or print in the unshaded areas only.

III. SOURCE OWNERS AND OPERATORS

A. Source Owners

If more than 4 owners, copy this page and enter number of copies here

1
1. Name
2. Street or P.O. Box
3. City
4. State
5. Zip -

2
1. Name
2. Street or P.O. Box
3. City
4. State
5. Zip -

3
1. Name
2. Street or P.O. Box
3. City
4. State
5. Zip -

4
1. Name
2. Street or P.O. Box
3. City
4. State
5. Zip -

B. Source Operators

If more than 2 operators, copy this page and enter number of copies here

1
1. Name
2. Street or P.O. Box
3. City
4. State
5. Zip -

2
1. Name
2. Street or P.O. Box
3. City
4. State
5. Zip -

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

Please type or print in the unshaded areas only.

IV. UNIT IDENTIFICATION

A. Appendix A Units

If more than 4 units, copy this page and enter number of copies here →

1
1. Unit Name
2. Short Name
3. Unit ARP ID Number

2
1. Unit Name
2. Short Name
3. Unit ARP ID Number

3
1. Unit Name
2. Short Name
3. Unit ARP ID Number

4
1. Unit Name
2. Short Name
3. Unit ARP ID Number

B. Non-Appendix A Units

If more than 4 units, copy this page and enter number of copies here →

1
1. Unit Name
2. Short Name
3. Unit ARP ID Number

2
1. Unit Name
2. Short Name
3. Unit ARP ID Number

3
1. Unit Name
2. Short Name
3. Unit ARP ID Number

4
1. Unit Name
2. Short Name
3. Unit ARP ID Number

Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

V. AGREEMENT OF REPRESENTATION

The Designated Representative and Alternate Designated Representative for this source were selected under the terms of an Agreement of Representation that is binding on each and every owner and operator of the affected source and on each and every owner and operator of each affected unit at the source. Actual written notice of the Agreement of Representation has been given to each owner and operator of the source and of each unit, and notice has been published in a journal of national and general circulation for a period of two weeks.

The Designated Representative and Alternate Designated Representative have all necessary authority to carry out the duties and responsibilities that are assigned to the Designated Representative, owner or operator under 40 CFR Parts 72-78. If applicable, the Agreement of Representation specifies the terms and conditions under which the Alternate Designated Representative is to act in place of the Designated Representative.

Allowances and proceeds of allowance transactions *(mark one)*:

☐ Will be deemed to be held or distributed in proportion to each owner's legal, equitable, leasehold, or contractual reservation or entitlement and in accordance with Section 408(i) of the Act; or

☐ Are governed by an agreement with different terms that is binding on each and every person or entity with an ownership interest.

The Designated Representative and Alternate Designated Representative will abide by the fiduciary responsibilities assigned pursuant to 40 CFR Sections 72.20-72.25 and the Agreement of Representation.

VI. CERTIFICATIONS

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*

B. Signature	C. Date Signed

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Alternate Designated Representative *(please print)*

B. Signature	C. Date Signed

FOR EPA USE ONLY

1. Date Received: ____________
2. Date of Initial Review: ____________ By: ____________
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: ____________
3. Date of Final Approval: ____________ By: ____________
4. Date Notice Sent: ____________ By: ____________

Comments:

DRAFT 7220A
Date 10/21/91
Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY
Certificate of Representation
(Individual Unit Information)

Follow Instructions for Form 7220A.

I. UNIT IDENTIFICATION

A. Name

B. Unit Short Name

C. Unit ARP ID Number

II. UNIT OWNERS AND OPERATORS

A. Unit Owners — If more than 5 owners, copy this page and enter number of copies here

1
1. Name
2. Street or P.O. Box
3. City
4. State
5. Zip

2
1. Name
2. Street or P.O. Box
3. City
4. State
5. Zip

3
1. Name
2. Street or P.O. Box
3. City
4. State
5. Zip

4
1. Name
2. Street or P.O. Box
3. City
4. State
5. Zip

5
1. Name
2. Street or P.O. Box
3. City
4. State
5. Zip

Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

B. Operator If more than 1 operator, copy this page and enter number of copies here

1. Name

1

2. Street or P.O. Box

3. City

4. State

5. Zip

III. AGREEMENT OF REPRESENTATION

The Designated Representative and Alternate Designated Representative for this unit were selected under the terms of an Agreement of Representation that is binding on each and every owner and operator of the affected unit. Actual written notice of the Agreement of Representation has been given to each owner and operator of the unit, and notice has been published in a journal of national and general circulation for a period of two weeks.

The Designated Representative and Alternate Designated Representative have all necessary authority to carry out the duties and responsibilities that are assigned to the Designated Representative, owner or operator under 40 CFR Parts 72-78. If applicable, the Agreement of Representation specifies the terms and conditions under which the Alternate Designated Representative is to act in place of the Designated Representative.

Allowances and proceeds of allowance transactions *(mark one)*:

- ☐ Will be deemed to be held or distributed in proportion to each owner's legal, equitable, leasehold, or contractual reservation or entitlement, and in accordance with Section 408(i) of the Act; or
- ☐ Are governed by an agreement with different terms that is binding on each and every person with an ownership interest.

The Designated Representative and Alternate Designated Representative will abide by the fiduciary responsibilities assigned pursuant to 40 CFR Sections 72.20-72.25 and the Agreement of Representation.

IV. CERTIFICATIONS

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*

B. Signature	C. Date Signed

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Alternate Designated Representative *(please print)*

B. Signature	C. Date Signed

FOR EPA USE ONLY

1. Date Received: ____________
2. Date of Initial Review: ____________ By: ____________
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: ____________
3. Date of Final Approval: ____________ By: ____________
4. Date Notice Sent: ____________ By: ____________

Comments:

7220A/Pg. 2

BILLING CODE 6560-50-C

Phase I Acid Rain Permit Program Instructions for Forms #7220 and 7220A

Forms #7220 and 7220A—Certificate of Representation Forms

Introduction

Title IV of the Clean Air Act requires that the owners of record for each affected unit in the Acid Rain program must choose a Designated Representative and may choose an alternative Designated Representative to act when the Designated Representative is indisposed. The regulations that govern the Designated Representative are found at 40 CFR § 72.20 *et seq.* (Subpart B of the Title IV Permit Regulations). The owners must choose the Designated Representative and the Alternate through a process that assures that all owners have notice regarding the selection. All affected units at a single source must have the same Designated Representative, and all units that seek to participate in a multi-source substitution plan must be represented by the same Designated Representative.

The Designated Representative will be responsible for all submissions regarding the unit under his or her control, and will conduct allowance transactions for the unit. The Designated Representative shares liability with the Alternate Designated Representative, the owners and operators of the unit for any violations of the Acid Rain title.

The regulations state that EPA will neither issue an Acid Rain permit nor record any allowance transactions until the Designated Representative has filed and EPA has approved a complete certificate of representation. The request for certification must be filed on the standard forms provided for that purpose. The Certificate of Representation forms serve to identify each Phase I affected source for which a Designated Representative will be responsible (Form #7220), and to verify for the sources, as well as unit by unit, that the Designated Representative and Alternate Designated Representative are authorized to take responsibility for Acid Rain program submissions (Forms #7220 and 7220A). For Phase I, these forms must be submitted no later than February 15, 1993, (the deadline for Acid Rain Phase I permit applications). EPA recommends early submission of these forms to forestall delays in allowance transactions and permit processing.

Instructions for Form #7220—Certificate of Representation (Single Source)

Top Center of Each Page of the Form: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. Designated Representative Identification

A.–1. Enter the name, mailing address, and telephone and facsimile numbers for the Designated Representative and for the Alternate, if one is proposed.

II. Source Identification

In this section, provide the information for a source or facility that contains one or more affected units for which the person(s) named in Part I be serving as Designated Representative (and Alternate Designated Representative).

A. Name: Provide the name of the source or facility. This name will include the company name and a name for the source, *e.g.*, "ABC Utility Electric Power Station."

B–E. Mailing Address: Provide the source mailing address.

III. Source Owners and Operators of Record

A. Provide the name and mailing address of each owner of record for the source. The owner can be a person or a corporation. If there are more than four owners, photocopy this page before completing it, and indicate how many copies you are including.

B. Provide the name and mailing address for each operator of record of the source. These persons include [to be added]. If there are more than two operators, copy this page before completing it, and indicate how many copies you are including.

IV. Unit identification

List the affected units at the source identified in Part II, above. In Section A, provide information for Appendix A units. In Section B, list any non-Appendix A units that you will be proposing as part of a compliance option, or other units at the source for which you would like to designate a representative for purposes of allowance transactions. (You will need to complete a Standard Form 7220A for each of the units you list.) For each unit provide the following:

1. Fill in the name of the affected unit (*e.g.*, "ABC Elect. Gen. Unit #4.")

2. Give a short name that is commonly used or could be used as an easy identification of the unit (*e.g.*, "ABC #4.")

3. Provide the Acid Rain Program Identification Number for the unit, which is the source number appearing at the top center of this form plus three digits that identify the unit (*e.g.*, "004"). Enter the three digits in the space provided. (Acid Rain Program unit ID numbers are listed in Appendices A and B of 40 CFR part 72.)

V. Agreement of Representation

This section lists the requisite elements for the Agreement of Representation between the Designated Representative and the Alternate Designated Representative and the owners. EPA will not accept and certify the Designated Representative or the Alternate Designated Representative to represent the unit in all Acid Rain regulatory matters unless the Designated Representative (or both of them) certifies that such an agreement exists.

The applicant will need to check the box that more accurately describes the term of the agreement relating to distribution of proceeds from allowance transfers.

EPA will not review the agreement, nor will it become a party to any disputes regarding the agreement. EPA, however, will enforce against any false certification concerning the existence or terms of such an agreement.

IV. Certification

The proposed Designated Representative and Alternate Designated Representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See Part III, Section A of the Forms Instructions Package for more information about the legal effect of certification.

Instructions for Form #7220A—Certificate of Representation (Individual Unit Information)

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. Unit Identification

A.–C. Enter the same information you entered for the unit in Part IV of Form 7220.

II. Owners and Operators of Record

A. Provide the name and mailing address of each owner of record for the unit. The owner can be a person or a corporation. If there are more than five owners, photocopy this page before completing it and indicate how many copies you are including.

B. Provide the name of each operator of record for the unit. These persons include (to be added). If there is more than one operator, photocopy this page before completing it and indicate how many copies you are including.

III. Agreement of Representation

This section lists the requisite elements for the Agreement of Representation between the Designated Representative and the Alternate Designated Representative and the owners. EPA will not accept and certify the Designated Representative or the Alternate Designated Representative to represent the unit in all Acid Rain regulatory matters unless the Designated Representative (or both of them) certifies that such an agreement exists.

The applicant will need to check the box that more accurately describes the term of the agreement relating to distribution of proceeds from allowance transfers.

EPA will not review the agreement, nor will it become a party to any disputes regarding the agreement. EPA, however, will enforce against any false certification concerning the existence or terms of such an agreement.

IV. Certification

The proposed Designated Representative and Alternate Designated Representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See Part III, Section A of the Forms Instruction Package for more information about the legal effect of certification.

BILLING CODE 6560-50-M

FORMS 7231 AND 7231A

Application for Phase I Acid Rain Permit

Form 7231

Application for Phase I Acid Rain Permit (Source Information)

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average ____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

Form 7231A

Application for Phase I Acid Rain Permit (Unit Information)

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

DRAFT 7231
Date 10/21/91
Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY
Application for Phase I Acid Rain Permit
(Source Information)

Follow Instructions for Form 7231.

I. SOURCE IDENTIFICATION

A. Source Name and Mailing Address

1. Source Name

2. Street or P.O. Box

3. City | 4. State | 5. Zip -

B. Source Location

1. Street, Route Number or Other Specific Identifier

2. City | 3. State | 4. Zip -

5. County Name | 6. Phone *(area code & number)* - -

C. Other Source Information

1. Operating Company

2. NERC Region | 3. Aggregate Baseline *(mmBtu)*

II. UNIT IDENTIFICATION

A. Appendix A Units

If more than 4 units, copy this sheet and enter number of copies here

1. Unit Name
1
2. Short Name | 3. Unit ARP ID Number

1. Unit Name
2
2. Short Name | 3. Unit ARP ID Number

1. Unit Name
3
2. Short Name | 3. Unit ARP ID Number

1. Unit Name
4
2. Short Name | 3. Unit ARP ID Number

Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

B. Non-Appendix A Units If more than 4 units, copy this sheet and enter number of copies here →

1
1. Unit Name
2. Short Name
3. Unit ARP ID Number

2
1. Unit Name
2. Short Name
3. Unit ARP ID Number

3
1. Unit Name
2. Short Name
3. Unit ARP ID Number

4
1. Unit Name
2. Short Name
3. Unit ARP ID Number

III. CERTIFICATE OF REPRESENTATION

☐ Certificate of Representation for this source and each unit at this source is included (either original or copy).

IV. STANDARD PROVISIONS & PROHIBITIONS

A. Duties, Prohibitions and Liability

1. Duties. Each owner, operator, and designated representative of an affected unit shall have the following affirmative duties in connection with the Acid Rain program. Failure to fulfill or comply with these duties shall be a violation of the Act and of 40 CFR Part 72. The duties are as follows:
   a. To submit a permit application and proposed compliance plan under 40 CFR Part 72 in accordance with the deadlines specified in §72.30;
   b. To submit in a timely manner any additional information that the permitting authority requires for the complete review of a permit application;
   c. To operate any affected unit in compliance with the terms, conditions, requirements, and prohibitions of an Acid Rain permit application and proposed compliance plan properly submitted in accordance with Title IV of the Act and of 40 CFR Part 72 (including any amendments or modifications thereto required by the permitting authority), or of the superseding Acid Rain permit issued by the permitting authority;
   d. To operate the unit in compliance with the monitoring requirements of 40 CFR Part 75;
   e. In the case of an affected unit with excess emissions in any calendar year, to pay without demand the penalty required pursuant to 40 CFR Part 77; and,
   f. In the case of an affected unit with excess emissions in any calendar year, to comply with the offset planning requirements of 40 CFR Part 77 and an approved offset plan as required by 40 CFR Part 77.

2. Prohibitions. Any violation of the following prohibitions shall be a violation of the Act and 40 CFR Part 72 by the owners, operators and designated representative of the affected unit and/or affected source:
   a. No affected unit shall exceed the applicable emissions limitations of 40 CFR Parts 72-78, as follows:
      i. No affected unit shall emit sulfur dioxide in any calendar year in excess of the allowances held in the unit's Allowance Tracking System compliance subaccount as of the allowance transfer deadline for use in the calendar year as provided in 40 CFR Part 73. Each ton of sulfur dioxide emitted in excess of the allowances held shall constitute a separate violation of the Act.
      ii. No affected unit shall emit nitrogen oxides in excess of:
         A. the annual emissions limitation for the unit by the type of boiler, as specified in 40 CFR Part 76; or,
         B. the superseding limitation specified in an approved nitrogen oxides compliance option incorporated into the Acid Rain permit issued by the permitting authority in accordance with 40 CFR Part 72, Subpart D and 40 CFR Part 75;
   b. No person shall hold, use, or transfer any allowance except in accordance with Title IV of the Act and the regulations in 40 CFR Parts 72-78;
   c. No person shall use an allowance prior to the calendar year for which the allowance was allocated; and,
   d. No person shall make a false statement in any submission required under 40 CFR Parts 72-78, inclusive.

NOTE: Section IV. STANDARD PROVISIONS & PROHIBITIONS is continued on Page 3 of this form →

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

Please type or print in the unshaded areas only.

IV. STANDARD PROVISIONS & PROHIBITIONS (cont.)

3. Liability
   a. Any person who knowingly violates any requirement or prohibition of Title IV of the Act, of 40 CFR Parts 72-78, of an Acid Rain permit application filed pursuant to the requirements of Title IV of the Act and 40 CFR Parts 72-78, or of an Acid Rain permit, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to Section 113(c) of the Act.
   b. All owners, operators, and designated representatives of any affected units governed by a multi-unit compliance plan that is filed pursuant to the requirements of Title IV of the Act and 40 CFR Parts 72-78 shall be liable for any violation of the plan at any unit governed by the compliance plan, including liability for failure to fulfill the obligations specified in 40 CFR Part 7 and Section 411 of the Act.
   c. Any person who knowingly makes a false material statement in any record, submission, or report required by the Acid Rain program shall be subject to criminal enforcement pursuant to Section 113(c) of the Act and 18 U.S.C. 1001.
   d. No permit revision shall excuse past noncompliance.

B. Standard Provisions

1. Continuous Emissions Monitoring Requirements
   a. The owners, operators and designated representative of the units at this source shall comply with all the emissions monitoring requirements of 40 CFR Part 75, including:
      i. The duty to collect and report emissions data for each unit at the source, to adopt quality assurance procedures, and to conduct quality assurance reviews of the emissions monitoring system and the data for sulfur dioxide, nitrogen oxides, opacity and volumetric flow at each unit at the source as specified in 40 CFR Part 75; and,
      ii. The duty to calculate emissions pursuant to the missing data provisions of 40 CFR Part 75 if emissions monitoring data are not available for any affected unit during any period when such data are required.
   b. The requirements of 40 CFR Part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other provisions of the operating permit for the source.
   c. No affected unit or source shall use alternative monitoring system data or procedures unless the Administrator approves the alternative monitoring system in accordance with 40 CFR Part 75, and the unit operates the system in accordance with that approval.

2. Recordkeeping and Reporting Requirements
   a. The owners, operators, and designated representative of the affected units at the affected source shall keep the following records for a period of 5 years on site at the affected source governed by the permit or permit application.
      i. The certificate of representation for the designated representative for the source and each unit at the source, and all documents that support the certificate, as provided in 40 CFR Part 72, Subpart B;
      ii. All emissions monitoring information, including but not limited to calibration and maintenance records, quality assurance procedures information, and raw emissions and operation data used to generate emissions reports that a source or unit must collect under the requirements of 40 CFR Part 75;
      iii. Copies of all reports required by 40 CFR Parts 72-78; and,
      iv. Copies of all documents, contracts, agreements, guarantees, schedules, operating procedures, allowance documentation, or any other records of information used to complete the permit application and compliance plan or to demonstrate compliance with the requirements of the Acid Rain program.
   b. The designated representative shall submit quarterly and annual compliance certifications as required by 40 CFR Part 72 Subpart K and other provisions of 40 CFR Parts 72-78.

3. Allowance Information
   a. An allowance allocated by the Administrator under the Acid Rain program is a limited authorization to emit sulfur dioxide in accordance with the provisions of Title IV of the Act and 40 CFR Parts 72-78. Nothing in Title IV, in 40 CFR Parts 72-78, in this permit application or in any provision of law shall be construed to limit the authority of the United States to terminate or limit the authorization.
   b. An allowance allocated by the Administrator under the Acid Rain program does not constitute a property right.

4. Effect on Other Authorities
   a. Nothing in Title IV, in 40 CFR Parts 70-78, or in this application shall be construed as limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by a unit shall not affect the applicability of, or the affected source's obligation to comply with, any other provision of the Act, including the provisions of Title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans.
   b. Nothing in Title IV, in 40 CFR Parts 70-78, or in this application shall be construed as requiring a change of any kind in any State law regulating electric utility rates and charges, or as affecting any State law regarding such State regulation, or as limiting such State regulation, including any prudence review requirements under such a State law.
   c. Nothing in Title IV, in 40 CFR Parts 70-78, or in this application shall be construed as modifying the Federal Power Act or as affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act.
   d. Nothing in Title IV, in 40 CFR Parts 70-78, or in this application shall be construed to interfere with or impair any program for competitive bidding for power supply in a State in which such program is established.

5. Definitions. This application adopts by reference all definitions found at 40 CFR Part 72.

V. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative

B. Signature	C. Date Signed

Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

FOR EPA USE ONLY

1. Date Received: ____________
2. Date of Initial Review: ____________ By: ____________
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: ____________

3. Date of Final Approval: ____________ By: ____________
4. Date Notice Sent: ____________ By: ____________

Comments:

DRAFT 7231A
Date 10/21/91
Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Application for Phase I Acid Rain Permit
(Unit Information)

Follow Instructions for Form 7231A.

I. UNIT IDENTIFICATION

A. Unit ARP ID Number

B. Short Name

C. This unit is:
- [ ] 1. Appendix A
- [ ] 2. Non-Appendix A
  - [ ] a. Existing
  - [ ] b. Opt-In
  - [ ] c. New

D. This unit is:
- [ ] 1. Coal fired *(complete I.E.)*
- [ ] 2. Multi-header
- [ ] 3. Shares a common stack *(see monitoring plan)*

E. This unit has the following boiler type:
- [ ] 1. Tangentially fired
- [ ] 2. Dry bottom wall-fired

II. EMISSIONS LIMITATIONS

A. Sulfur Dioxide

1. Basic Phase I Annual Allowance Allocation: *(TPY)* →

The allocation listed at II.A.1. above will be the allocation to the unit for each year of Phase I unless the Designated Representative submits or activates a compliance option pursuant to Section V of this form that is approved by the Administrator under which an alternate allocation is established.

2. Most stringent Federally-enforceable Sulfur Dioxide emissions limitation applicable to the unit (other than the Acid Rain Program limitation) at the time of the application: →

B. Nitrogen Oxides

- [ ] 1. This unit is subject to Title IV emissions limits in Phase I (1995-1999), and:
  - [ ] a. Will meet the Title IV emissions limit for the boiler type listed in I.E., above.
  - [ ] b. Proposes a Nitrogen Oxides compliance option *(see Section V, below, and attached compliance plan forms).*
- [ ] 2. This unit is not subject to Title IV emission limits at this time.

3. Most stringent Federally-enforceable Nitrogen Oxides emissions limitation applicable to the unit (other than the Acid Rain Program limitation) at the time of the application: →

III. UTILIZATION INFORMATION

A. Heat Input Baseline *(mmBtu)*		B. Generation Baseline *(Kwh)*	

C. Annual Projections of Utilization:

	1995	1996	1997	1998	1999
Heat Input *(Btu)*					
Generation *(Kwh)*					

IV. MONITORING PLAN

(Mark one):

- [ ] A. This unit has an approved monitoring plan.
- [ ] B. A monitoring plan is included for approval.
- [ ] C. Each monitor at this unit has been certified.
- [ ] D. Initial monitor verification test results are included for certification.
- [ ] E. Initial monitor verification test results were submitted for certification on the following date but no notification has been received *(mm/dd/yy)*: →
- [ ] F. Initial monitor verification test results will be submitted in accordance with Part 75.

Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

V. COMPLIANCE PLAN INFORMATION

A. Sulfur Dioxide Compliance Plan

1. This Appendix A Unit *(mark a or b)*:

☐ a. Will hold allowances to emit not less than its total annual emissions and will not use other compliance options.

☐ b. Will hold allowances to emit not less than its total annual emissions and seeks approval for the following compliance option(s): *(mark all that are applicable)*

☐ i. Reduced utilization *(attach Form #XXXX)*.

☐ ii. Substitution *(attach Form #XXXX)*.

☐ iii. Phase I extension *(attach Form #XXXX)*.

2. This Non-Appendix A Unit seeks approval for its participation in Phase I as:

☐ a. An opt-in unit *(attach Form #XXXX)*.

☐ b. Part of a reduced utilization plan *(attach Form #XXXX)*.

☐ c. Part of a substitution plan *(attach Form #XXXX)*.

☐ d. Part of a Phase I extension plan *(attach Form #XXXX)*.

B. Nitrogen Oxides Compliance Plan

This Appendix A Unit:

☐ 1. Will meet the Title IV statutory emissions limit.

☐ 2. Seeks approval for the following compliance option(s):

☐ a. Emissions averaging *(attach Form #XXXX)*.

☐ b. Alternative emissions limits *(attach Form #XXXX)*.

☐ c. Deadline extension *(attach Form #XXXX)*.

VI. STANDARD PROVISIONS AND PROHIBITIONS

The standard provisions and prohibitions from Part IV of the Application for a Phase I Acid Rain Permit (Source Information) are incorporated by reference and shall apply with full force and effect to this unit.

VII. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*

B. Signature

C. Date Signed

FOR EPA USE ONLY

1. Date Received: ____________
2. Date of Initial Review: ____________ By: ____________
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: ____________
3. Date of Final Approval: ____________ By: ____________
4. Date Notice Sent: ____________ By: ____________

Comments:

7231A/Pg. 2

BILLING CODE 6560-50-C

Phase I Acid Rain Permit Program Instructions for Forms #7231 and 7231A

Forms #7231 and 7231A—Application for Phase I Acid Rain Permit

Introduction

Clean Air Act Section 408 and the regulations implementing that section at 40 CFR Part 72 establish a permit program for affected sources under the Acid Rain Program. Subpart C of those regulations, 40 CFR §§ 72.30 *et. seq.*, sets forth the requirements for and contents of Acid Rain permit applications and compliance plans.

Briefly, in Phase I the Designated Representative for each Phase I affected source must submit a permit application and compliance plan for that source. These will include sources with Appendix A units and sources with Appendix B units that become affected units when they are brought into Phase I under an Acid Rain compliance option. When a given source consists of more than one unit, the Designated Representative must file a compliance plan for the source (or "facility") that covers all such units. However, for each unit, the Designated Representative must demonstrate individual compliance with the applicable Acid Rain Program limits.

This permit application forms are designed to accommodate both of these requirements. For each source that the Designated Representative represents, he or she will submit source-identifying information on SF#[7231]. The Designated Representative also must submit a unit application of SF#[7231A] that will state the emissions limitations for the unit and will indicate how the unit will comply with those limitations. For a unit that plans an Acid Rain compliance option (*e.g.*, reduced utilization, substitution), the Designated Representative also will be required to complete the form or forms designed to allow the applicant to demonstrate compliance through any such alternative plan. Instructions for those compliance options forms accompany the individual forms. The source information form, application forms for the units at the source and all attached compliance option forms constitute the "Source Compliance Plan."

The statute and regulations provide that the permit application and compliance plan shall be binding on the owner, operator and Designated Representative of the unit and shall be enforceable in lieu of a permit until the Administrator either issues a permit to the source or disapproves the application. Permit applications are due for all Phase I affected sources (see Section II of the general instructions for "Who Must Apply") by **February 15, 1993.** Approved permits and compliance plans will be effective **January 1, 1995 through December 31, 1999.**

Instructions For Form 7231—Application for Phase I Acid Rain Permit (Source Information)

Top Center of Each Page of the Form: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. Source Information

A. *Name and Mailing Address:* Provide the name and mailing address of the source or facility for which this application is filed. This name will include the company name and a name for the source, *e.g.*, "ABC Utility Electric Power Station."

B. Location

1–4. Provide a descriptive address for the source; if there is no street address or route number, give the most accurate alternative geographic information (*e.g.*, "Intersection of Rts. 6 and 502" or the section number from county records). If the location is the same as the mailing address given in I A, above, enter "Same as above" on line B 1 and do not complete B 2–4.

5. List the county in which the source is located.

6. Provide the main phone number for the source.

C. Other Source Information

1. Provide the name of the Operating Company for the source.

2. Provide the NERC region or sub-region in which the source is located.

3. Enter the aggregate baseline (in mmBtu) of all Phase I units in the system of which the source is a part.

II. Unit Identification

List the affected units. Provide information for Appendix A units in Section A and for non-Appendix units in Section B. List only those non-Appendix A units that you will be proposing as part of an alternative compliance plan. (You will need to complete a Standard Form 7231A for each of the units you list in either Section A or Section B.)

For each unit: 1. Fill in the name of the affected unit (*e.g.*, "ABC Elect. Gen. Unit #4.")

2. Give a short name that is commonly used or could be used as an easy identification of the unit (*e.g.*, "ABC #4.")

3. Provide the Acid Rain Program Identification Number for the unit. This is the source number appearing at the top center of this form plus three digits that identify the unit (*e.g.*, "004"). Enter the three digits in the space provided. (Acid Rain Program ID numbers are listed in Appendices A and B of 40 CFR Part 72.)

III. Certificate of Representation

Mark the box to indicate that this application includes the original Certificate of Representation forms or a copy of the forms previously submitted.

IV. Standard Provisions and Prohibitions

These provisions and prohibitions apply to all Acid Rain permit applications and proposed compliance plans, which are binding until EPA either makes an initial permitting decision or disapproves the application. These provisions apply to the source and to all affected units that are a part of that source.

V. Certification

The Designated Representative must sigh this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See Part III, Section A of the Forms Instructions Package for more information about the legal effect of certification.

Instructions for Form 7231A—Application for Phase I Acid Rain Permit (Unit Information)

Top Center of Each Page of the Application: Enter the Acid Rain Program Identification Number (the AIRS number) for the source at which the unit is located.

I. Unit Identification

A. Enter the unit Acid Rain Identification Number; this number (15 digits) appears in Appendix A or Appendix B, wherever the unit is listed.

B. Enter the short name that is commonly used or could be used for easy identification of the unit (*e.g.*, "ABC #4").

C. Mark whether or not the unit is listed on Appendix A in 40 CFR part 73. If you are submitting the application for a non-Appendix A unit, further identify the unit:

2a. An Existing Unit is a unit that commenced commercial operation before November 15, 1990, including any unit that is modified, reconstructed or repowered after November 15, 1990. Existing unit does not include a simple combustion turbine or a unit that serves a generator with a nameplate capacity of 25 MWe or less.

2b. An Opt-In Unit is a unit defined in 40 CFR Part 74 as ____.

2c. A New Unit is: (i) any unit that commenced commercial operation on or after November 15, 1990, including any unit that serves a generator with a nameplate capacity of 25 MWe or less or is a simple combustion turbine; or, (ii) any unit that commenced commercial operation prior to November 15, 1990 but only began to serve a generator with a nameplate capacity of greater than 25 MWe on November 15, 1990 or after.

D. Mark all applicable boxes that apply to this unit:

1. Mark whether the unit is coal-fired. Only coal-fired units can become affected units for nitrogen oxides, and only those units with tangentially fired boilers or dry bottom wall-fired boilers (other than units applying cell burner technology) are subject to a Title IV Nitrogen Oxides emission limit in Phase I.

2. Indicate whether the unit is multi-header.

3. Indicate whether this unit shares a common stack. All units that share a common stack must complete a common stack plan, on SF#____.

E. Indicate whether this unit has either or both of the boiler type(s) listed by marking appropriate check boxes.

II. Emissions Limitations

A. Sulfur Dioxide Emissions Limitations

1. For a unit that is listed in Appendix A at 40 CFR Part 72, enter the allowance allocation from the Appendix. If the unit proposes a compliance option that would alter the allowance allocation, you will be indicating this in Part V of the form.

2. Enter the most stringent federally enforceable sulfur dioxide emissions emulation that is applicable at the time of the application.

B. Nitrogen Oxides

Mark either 1 or 2.

1. If you checked either box in Part 1 E, above, this unit is regulated under Title IV for

nitrogen oxides in Phase I. Mark this box, and indicate whether the unit:

a. will comply with the statutory limit, or

b. proposes different limit under a Nitrogen Oxide compliance option.

2. Mark this box if your unit does not have either of the boiler types listed in Part 1 E, above. This means that the unit will not be subject to *Title IV* Nitrogen Oxides limits at this time. This does not preclude the regulation of Nitrogen Oxides under another title of the Act through the source operating permit.

3. Enter the most stringent federally enforceable nitrogen oxides emissions limitation that is applicable at the time of the application.

III. Utilization Information

Complete This Section for Appendix A Units Only.

A. Enter the heat input baseline, which is listed in Appendix A at 40 CFR part 72.

B. Enter the average annual generation during the baseline years.

C. Enter annual projections of utilization for the unit for all years of Phase I (1995-1999).

If utilization is projected to fall below the baselines given in A and B, above, you must file a reduced utilization plan. Check box b i under Section V A in this form and submit standard form #[7243] with this application.

IV. Monitoring Plan

Clean Air Act Section 412 requires that all units that are subject to Title IV permitting requirements monitor sulfur dioxide, nitrogen oxides, opacity and volumetric flow using Continuous Emission Monitors (CEMS) or an alternative monitoring system that is demonstrated to provide data essentially equivalent to that provided by a CEMS.

Indicate the status of the monitoring plan by marking the appropriate box.

V. Compliance Plan Information

Under § 408(b) of the CAAA, all Acid Rain permit applicants are required to submit a compliance plan that indicates how the unit will meet the emissions reduction requirements of Title IV. Section 408(b) of the Clean Air Act provides that a unit can meet compliance planning requirements by submitting a statement that the unit will meet the applicable emissions limitations in a timely manner. For any unit that proposes to meet the emissions limitations requirements by means of an Acid Rain Program compliance option other than the standard SO_2 and NO_x options, the proposed compliance plan must include a description of the schedule and means by which the unit will rely on one or more of the methods in the manner and time authorized under the statute.

A. SO_2 Compliance Plan

1. For Appendix A units—choose either a or b. In all cases, the unit *must hold sufficient allowances.*

a. Mark here if compliance will be achieved through allowances alone.

b. Mark here if the unit seeks to meet the SO_2 limits through an Acid Rain Program compliance option, and check all applicable plans submitted for which approval is sought. The Designated Representative of a unit may seek approval for more than one compliance option and may activate approved options at a later date.

i. Reduced Utilization Plan: Clean Air Act Section 408(c)(1)(b) and the regulations implementing that section at 40 CFR § 72.43, require that a unit file a reduced utilization plan if the unit will meet its emission reduction requirement through reduced utilization. If the projected utilization figures listed in this application at Part III fall below the baseline figures listed there then the unit *must* file a plan. A unit also may file a reduced utilization plan to be activated during the permit term in the event that reduced utilization becomes a necessary or desirable compliance option. A more complete description of this provision and of the components of this plan are provided in the instructions for form #[7243].

ii. Substitution Plan: Clean Air Act Section 404(b) and the regulations implementing that part at 40 CFR § 72.41 allow Appendix A units to propose a reassignment of the SO_2 emission reduction requirements at the units to Appendix B "substitute" units that are under the control of the original units' Designated Representative. A more complete description of this provision and of the components of a substitution plan are provided in the instructions for form #[7241].

III. Qualified Phase I Extension Plan: Clean Air Act Section 404(d) and the regulations implementing that section at 40 CFR § 72.42 allow a unit to petition for an extension of its Phase I emissions limitation requirement. To qualify for such an extension, the unit must either employ a qualifying Phase I technology (see glossary) or transfer its Phase I emissions reduction obligation to a unit employing a qualifying Phase I technology. A more complete description of this provision and of the components of a qualified extension plan are provided in the instructions for form #[7242].

2. Non-Appendix A Units.

If this application is filed for a unit that is not listed on Appendix A of 40 CFR Part 72, then indicate why the unit seeks approval for its participation in Phase I as follows:

a. Opt-In Units: [to be added]

b. Reduced Utilization Plan: Clean Air Act Section 408(c)(1)(b) and the regulations implementing that section at 40 CFR § 72.43, require that a unit file a reduced utilization plan if the unit will meet its emission reduction requirement through reduced utilization. In some cases reduced utilization plans will involve using non-Appendix A units to provide electrical generation to compensate for the reduced generation at the Appendix A units. A more complete description of this provision and of the components of this plan are provided in the instructions for form #[7243].

c. Substitution Plan: Clean Air Act Section 404(b) and the Regulations implementing that part at 40 CFR § 72.41 allow Appendix A units to propose a reassignment of the SO_2 emission reduction requirements at the units to Appendix B "substitute" units that are under the control of the original units' Designated Representative. A more complete description of this provision and of the components of a substitution plan are provided in the instructions for Form #[7241].

d. Qualified Phase I Extension Plan: Clean Air Act Section 404(d) and the regulations implementing that section at 40 CFR § 72.42 allow a unit to petition for an extension of its Phase I emissions limitation requirement. To qualify for such an extension, the unit must either employ a qualifying Phase I technology (see glossary) or transfer its Phase I emissions reduction obligation to a control unit that is, a unit employing a Qualifying Phase I Technology. Non-Appendix A units can serve as control units. A more complete description of this provision and of the components of a qualified extension plan are provided in the instructions for form #[7242].

B. NO_x Compliance Plan

All coal-fired units that have either a tangentially fired or a dry bottom wall-fired boiler (but not boilers employing cell burner technology) are regulated in Phase I and are required to meet Title IV NO_x emissions limits by 1995. A unit can apply for alternative limits or can apply for an extension of the limits under NO_x compliance options.

The unit will fill in either subsection 1 or 2. The directions are the same for both Appendix A and Non-Appendix A Units.

a. Title IV Limit: Mark this box if you plan to meet the statutory emissions limit that applies to the boilers or boilers at your unit.

b. Mark this box if the unit seeks approval for one or more of the listed compliance options, and also indicate the options for which approval is sought by marking the appropriate box(es):

i. Emissions Averaging: Clean Air Act Section 407(e) and the regulations implementing that Part at 40 CFR § 72.46, allow the Designated Representatives of two or more units subject to the Title IV emissions limit to submit a proposal to set alternative contemporaneous annual emissions limits for the units. These new limits must assure that the resulting emissions will be no greater than they would have been had the statutory limits been applied at each unit. A more complete description of this provision and of the components of the plan will be included in Part 76.

ii. Alternative Emission Limitation: Clean Air Act Section 407(d) and the regulations implementing that Section at 40 CFR § 72.47 allow the Administrator to authorize an alternative NO_x emissions limit for a unit that can adequately demonstrate its inability to meet the limit using NO_x low burner technology. A more complete description of this provision and of the components of the plan will be included in Part 76.

iii. Deadline Extension: Clean Air Act Section 407(d) and the regulations implementing that Section at 40 CFR § 72.48 allow the Administrator to extend the deadline by up to 15 months for compliance by a unit if that unit can demonstrate adequately that the technology necessary to meet the statutory requirement is not in adequate supply. A more complete description of this provision and of the components of the extension will be included in Part 76.

VI. Standard Provisions and Prohibitions

The standard provisions and prohibitions in the source application form (SF# 7231) are incorporated by reference into this unit application and apply with full force and effect to this unit.

VII. Certification

The Designated Representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See Part III, Section A of the Forms Instructions Package for more information about the legal effect of certification.

BILLING CODE 6560-50-M

FORM 7241

Substitution Plan

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

DRAFT 7241
Date 10/21/91
Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Substitution Plan (Multiple Unit/Multiple Source)

Follow instructions for Form 7241.

I. APPENDIX A UNITS

If more than 3 units, copy this page and enter number of copies here →

	A. Unit ARP ID Number	B. Short Name	C. Emissions Rate	D. 1985 Tons
1				
2				
3				

E. Total 1985 Tons

F. Total Annual Reductions Without Plan

G. Proposed Annual Tons Sulfur Dioxide:

	1995	1996	1997	1998	1999
1 Proposed Tons SO_2					
2 Proposed Tons SO_2					
3 Proposed Tons SO_2					
H. Total Proposed Tons SO_2					

I. Total Proposed Annual Reductions *(TPY)*	1995	1996	1997	1998	1999

II. SUBSTITUTION UNITS

If more than 3 units, copy this page and enter number of copies here →

☐ I include a copy of a complete permit application for the other sources at which any substitution units in this plan are located

	A. Unit ARP ID Number	B. Short Name	C. Emissions Rate	D. 1985 Tons
1				
2				
3				

E. Total 1985 Tons

F. Total Annual Reductions Without Plan

G. Proposed Yearly Tons Sulfur Dioxide Required to Satisfy the Plan:

	1995	1996	1997	1998	1999
1 Proposed Tons SO_2					
2 Proposed Tons SO_2					
3 Proposed Tons SO_2					
H. Total Proposed Tons SO_2					

I. Total Proposed Annual Reductions Required to Satisfy the Plan *(TPY)*	1995	1996	1997	1998	1999

III. ACTIVATION AND TERMINATION OF PLAN

A. Activation

Choose one:

☐ 1. If approved, this plan will go into effect on *(mm/dd/yy)*:

☐ 2. The Designated Representative will notify the Administrator of activation of the approved plan.

B. Termination

This plan will remain in effect until *(mm/dd/yy)*:

Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

IV. DOCUMENTATION OF EMISSIONS REDUCTIONS

Year	A. Total Proposed Annual Reduction from Appendix A Units	+	B. Total Proposed Annual Reduction from Substitution Units Required to Satisfy the Plan	≥	C. Total Annual Reductions Without Plan from Appendix A Units	+	D. Total Annual Reductions Without Plan from Substitution Units
1995		+		≥		+	
1996		+		≥		+	
1997		+		≥		+	
1998		+		≥		+	
1999		+		≥		+	

V. STANDARD PROVISIONS & PROHIBITIONS

A. Emissions Limitations

1. **Sulfur Dioxide.** Each unit governed by an approved substitution plan shall not emit Sulfur Dioxide in excess of the allowances held in the Allowance Tracking System Compliance subaccount for that unit for that calendar year.
2. **Nitrogen Oxides.** Any unit governed by an approved substitution plan shall not emit Nitrogen Oxides in excess of the applicable rate as specified in Section II.B. of the attached permit application.

B. Test Methods/Monitoring

Each unit governed by an approved substitution plan shall monitor emissions as specified in Section V of the attached permit application and in accordance with Part 75.

C. Recordkeeping Requirements

Each unit governed by an approved substitution plan shall comply with all recordkeeping requirements as specified in the attached permit application.

D. Reporting/Compliance Certification Requirements

Each unit governed by an approved substitution plan shall comply with all reporting and compliance certification requirements as specified in the attached permit application.

E. Prohibitions and Liability

1. It shall be unlawful for the Designated Representative of a unit listed in Appendix A to use any substitute unit except pursuant to a substitution plan duly submitted and approved by the Administrator pursuant to this part.
2. Owners and operators and the Designated Representative of an Appendix A or substitute unit operated in violation of 40 CFR Section 72.41 shall be liable for any such violation at any unit governed by the plan including liability for failure to fulfill the obligations specified in 40 CFR Part 77. Any such violation shall be a violation of the Act.

VI. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*

B. Signature

C. Date Signed

FOR EPA USE ONLY

1. Date Received: ____________
2. Date of Initial Review: ____________ By: ____________
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: ____________
3. Date of Final Approval: ____________ By: ____________
4. Date Notice Sent: ____________ By: ____________

Comments:

Phase I Acid Rain Permit Program—Instructions for Form #7241

Form #7241—Substitution Plan

Introduction

Clean Air Act section 404(b) and the regulations implementing that section at 40 CFR 72.41 allow the designated representative for appendix A units to submit a proposal to reassign all or part of the units' Phase I sulfur dioxide emissions reductions requirement to any appendix B unit or units ("substitute units") under the control of the same designated representative. The proposal must identify the original and substitute units, propose new emissions limitations for the units in the plan, and demonstrate that the new limitations will achieve an equal or greater emissions reductions than would have been achieved by all of the units without the substitution.

The deadline for the submission of substitution plans is February 15, 1993. A substitution plan can only be in effect during Phase I (January 1, 1995–December 31, 1999) but the unit may elect to activate its approved substitution plan at any time during the Phase.

The appendix B units that are brought into Phase I become affected units for Phase I. The designated representative must file a Phase I Acid Rain Permit Application for each such unit, and the units must meet all applicable requirements.

Instructions

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source to which you are attaching this plan. If more than one source is involved, you can save some time by leaving the spaces for the source Identification Number blank, and completing the plan form up through part IV. Then make enough photocopies of the plan forms for each source involved, fill in the source numbers, and sign form individually.

I. Appendix A Units

Unit Identification: Identify the original affected "Appendix A" unit or units that are proposed for this substitution plan. If more than three units are proposed, photocopy this form and enter the number of copies in the space provided.

Provide the Acid Rain Program Identification Number for the unit(s): you will find this in appendix A of 40 CFR part 72.

B. Enter the short name for the unit given in the Acid Rain Application (SF# 7231A) at part I, section B.

C. Enter the lesser of the actual or allowable 1985 emissions rates for the unit, from appendix A.

D. Enter the total 1985 tons for each unit. The sample worksheet in Figure 1 indicates the necessary calculations for the proposed units.

Figure 1: Worksheet

a. ________ (mmBtu)
b. ________ (lbs/mmBtu)
c. ________ (lbs)
d. ________ (tons)

For each unit: a. Enter the baseline (from appendix A).

b. Enter the lesser of the 1985 actual or allowable emissions rates (from Column C of the form).

c. Enter the product of the baseline multiplied by the emissions rate.

d. Divide by 2,000 to get tons. Enter this figure in column D in the space corresponding to the unit.

E. Total the figures in column D and enter total 1985 tons for these three units.

F. To calculate the Total Annual Reductions without the plan, add together the allowance allocations for each of the units (from appendix A). Subtract this total from the total 1985 tons (entered at E) and enter the result.

G. Proposed Yearly Tons SO_2 Under Plan: For each year that the substitution plan is proposed, fill in the proposed tons of SO_2 for that year (place information in the spaces corresponding to the numerical listing in Section A). If a plan is not proposed for a particular year, enter "NO PLAN PROPOSED" so that it is clearly readable in the white space.

H. Add down the columns and enter sum of all proposed tons for each year of the plan.

I. Enter the Total Proposed Annual Reductions for all the appendix A units. To calculate this figure, subtract the Total Proposed Tons listed in I H from the Total 1985 Tons (figure listed in ID)

Note: This number will be a negative number if the Appendix A unit will increase emissions from 1985 levels.

II. Substitution Units

Unit Identification: Identify the substitution units that are proposed for this substitution plan. If more than three units are proposed, photocopy this form and enter the number of copies in the space provided.

A. Provide the Acid Rain Program Identification Number for the unit(s): you will find this in appendix B of 40 CFR part 72.

B. Enter the short name for the unit given in the unit Acid Rain Application (SF# 7231A) at part I, section B.

C. Enter the lesser of the actual or allowable 1985 emissions rate.

D. Enter the total 1985 tons for each unit. The sample worksheet in Figure 2 indicates the necessary calculations for each proposed unit.

Figure 2: Worksheet

a. ________ (mmBtu)
b. ________ (lbs/mmBtu)
c. ________ (lbs)
d. ________ (tons)

For each unit: a. Enter the baseline (from appendix B).

b. Enter the emissions rate entered in column C of the form.

c. Enter the product of the baseline multiplied by the emissions rate.

d. Divide by 2,000 to get tons. Enter this figure in column D in the space corresponding to the unit.

E. Add down Column D and enter Total 1985 Tons for these units.

F. If any of the substitution units are subject to a more stringent federally enforceable emissions rate than the rate entered at II C above at the time of the application, you must calculate the reductions that would have occurred without the plan for those units. To do so, use Figure 3 to compute the TPY resulting from application of the stricter federal limit for each unit. Sum the Figure 3 totals for all units, and from this sum, subtract the figure entered at II E. Enter the total at E.

Figure 3: Worksheet

a. ________ (mmBtu)
b. ________ (lba/mmBtu)
c. ________ (lba)
d. ________ (tons)

For each unit: a. Enter the baseline (from Appendix B).

b. Enter the most stringent federally enforceable SO_2 emissions rate applicable to the unit at the time of the application.

c. Enter the product of the baseline multiplied by the emissions rate.

d. Divide by 2,000 to get tons. Enter this figure in column D in the space corresponding to the unit.

G. Proposed Yearly Tons SO_2 Under Plan: For each year that the substitution plan is proposed, fill in the Proposed Tons of SO required to satisfy the proposed plan for each unit (place information in the spaces corresponding to the numerical listing in Section A.)

Do not enter your actual projected emissions if they are less than the emissions required to satisfy the plan. If a plan is not proposed for a particular year, enter "NO PLAN PROPOSED" so that it is clearly readable in the white space.

H. Enter sum of all proposed tons for the proposed year of the plan.

I. Enter the Total Proposed Annual Reductions for all the substitute units. To calculate this figure, subtract the Total Proposed Tons for the units for that year (listed in II H) from the Total 1985 Tons (for the units listed in II E).

III. Activation of Plan

A. Enter the date on which the plan, if approved, will go into effect, or indicate that you seek to activate this plan (if approved) at a later date.

B. Enter the date the plan will terminate.

IV. Documentation of Emissions Reductions

This section of the form will indicate whether the proposed substitution plan will achieve adequate emissions reductions. If you have more than three appendix A or substitution units, total the figures from all pages for entry in this summary.

For each year: A. Enter the figure for Total Proposed Annual Reductions from appendix A Units from part I, section I for each year. If no plan is proposed for that year, indicate in the first white space with the entry of "Not Applicable" ("N/A").

B. Enter the figure for total annual reductions from the substitute units from part II, section H for the appropriate year.

C. Enter the total Annual Reductions Without Plan from appendix A units from part I, section F.

D. Enter the total Annual Reductions Without Plan from the substitute units from part II, section F above.

The sum of the figures entered at A and B must be greater than or equal to the sum of

the figures entered at C and D or the plan will not be acceptable on its face.

V. Standard Provisions and Prohibitions

You do not need to supply any information in this part, but you should read these provisions carefully.

VI. Certification

The Designated Representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See part III, section A of the Forms Instructions Package for more information about the legal effect of certification.

BILLING CODE 6560-50-M

FORMS 7242 AND 7242A

Phase I Extension Plan

Form 7242

Phase I Extension Early Ranking Application

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

Form 7242A

Phase I Extension Plan

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

DRAFT 7242
Date 11/05/91
Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Phase I Extension Early Ranking Application

Follow Instructions for Form 7242.

I. CONTROL UNIT(S)

This is control unit ____ of a total of ____ control units in this plan *(include a separate page 1 for each control unit)*

A. Unit ARP ID Number	B. Short Name	C. 1988-89 Average Emissions *(TPY)*

D. The unit is:

- ☐ 1. Appendix A
- ☐ 2. Substitution
- ☐ 3. Compensating

E. Projected Heat Input *(in mmBtu)*; Sulfur Dioxide Emissions Rate *(in lbs/mmBtu)* and Sulfur Dioxide Emissions *(in TPY)*

	1995	1996	1997	1998	1999
mmBtu					
lbs/mmBtu					
TPY					

	1995	1996	1997	1998	1999
F. Proposed Phase I Reserve Allowances Requested *(TPY)*:					
G. Proposed Total Allowance Allocation *(TPY)*:					
H. Available Transfer Capacity *(TPY)*:					

I. Qualifying Phase I Technology (90% Control Equipment):

1. Description of the Equipment:

a. Type of technology *(attach additional sheet if necessary)*: →

b. Design Sulfur Dioxide removal efficiency: →

c. Characteristics of the fuel and range of fuels for which the technology is designed *(attach additional sheets if necessary)*:

2. Schedules of Compliance:

a. Design Engineering *(mm/dd/yy)*:		b. Construction *(mm/dd/yy)*:		c. Operation *(mm/dd/yy)*:	
i. Start date		i. Start date		i. Start-up testing	
ii. Complete date		ii. Complete date		ii. Commence operation	

d. Control Equipment Maintenance Schedule:

e. Performance Test: Start Up Test *(mm/dd/yy)* →

J. Monitoring *(mark one)*:

☐ 1. This unit will monitor emissions in accordance with 40 CFR Section 75.12.

☐ 2. This unit will request approval for an alternative monitoring method for the determination of 90% control of Sulfur Dioxide because the above identified technology removes Sulfur Dioxide through a chemical reaction in the combustion process.

Source ARP ID Number

Please print or type in the unshaded areas only.

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

II. TRANSFER UNITS

If more than 5 units, include copies of this page and enter number of copies here

	A. Unit ARP ID Number	B. Short Name	C. 1988-89 Average Emissions *(TPY)*
1			
2			
3			
4			
5			

D. Projected Heat Input *(mmBtu)*, **Sulfur Dioxide Emissions Rate** *(lbs/mmBtu)* **and Sulfur Dioxide Emissions** *(TPY)*

		1995	1996	1997	1998	1999
1	*mmBtu*					
	lbs/mmBtu					
	TPY					
2	*mmBtu*					
	lbs/mmBtu					
	TPY					
3	*mmBtu*					
	lbs/mmBtu					
	TPY					
4	*mmBtu*					
	lbs/mmBtu					
	TPY					
5	*mmBtu*					
	lbs/mmBtu					
	TPY					

	E. Proposed Phase I Extension Reserve Allowances Requested *(TPY)*:		F. Proposed Total Allowance Allocation *(TPY)*:				
	1995	1996	1995	1996	1997	1998	1999
1							
2							
3							
4							
5							

Enter totals in the unnumbered blocks at the bottom of each column

Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

III. EMISSIONS TRANSFER RECONCILIATIONS

A. 1995 Reconciliation

If more than 5 transfer units, photocopy this sheet and enter the number of copies →

Transfer Unit	Control Unit				Total Emissions Being Transferred by Transfer Unit *(TPY)*
1					
2					
3					
4					
5					
Total Transfers to Control Units *(from this page)*					
Total Emissions Transferred *(from attachments)*					
Total Emissions Transferred					

B. 1996 Reconciliation

If more than 5 transfer units, photocopy this sheet and enter the number of copies →

Transfer Unit	Control Unit				Total Emissions Being Transferred by Transfer Unit *(TPY)*
1					
2					
3					
4					
5					
Total Transfers to Control Units *(from this page)*					
Total Emissions Transferred *(from attachments)*					
Total Emissions Transferred					

IV. RESERVE ALLOWANCE REQUEST

Total Phase I Extension Reserve Allowances requested for all control units and all transfer units governed by this proposed plan:	1995 - 1999

V. REQUIRED SUBMISSIONS

The following documents must accompany this application; if they do not, the Administrator will consider this application incomplete:

A. a copy of an executed contract for the design engineering and construction of the qualifying Phase I Technology for the control unit.

B. a certified vendor guarantee specifying the design Sulfur Dioxide removal efficiency and stating that the control unit technology will achieve at least 90% removal of Sulfur Dioxide for the type and range of fuels that will be used at the control unit.

VI. STANDARD PROVISIONS & PROHIBITIONS

The presumptive order of receipt established by this Early Ranking application shall be conditional on the following:

A. Submission by the designated representative for the source(s) where the affected unit(s) covered by the proposed plan is(are) located, of a complete and approvable proposed Phase I extension plan;

B. Timely modification of the proposed Phase I Extension Plan deemed necessary by the Administrator; and,

C. Yearly demonstrations that the qualifying Phase I technology has achieved 90% removal efficiency for Sulfur Dioxide.

Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

VII. CERTIFICATIONS

I certify that I am the Designated Representative for the units that are the control units in the Phase I extension plan. I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*		
B. Signature	C. DR ID Number	D. Date Signed

I certify that I am the Designated Representative for the unit identified below that is a transfer unit in the attached Phase I extension plan. I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*	B. Unit ARP ID Number	
C. Signature	D. DR ID Number	E. Date Signed

FOR EPA USE ONLY

1. Date Received: ____________
2. Date of Initial Review: ____________ By: ____________
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: ____________
3. Date of Final Approval: ____________ By: ____________
4. Date Notice Sent: ____________ By: ____________

Comments:
____
____

7242/pg.4

DRAFT 7242A
Date 11/05/91

Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Phase I Extension Plan

Follow Instructions for Form 7242A.

I. CONTROL UNIT(S)

This is control unit ____ of a total of ____ control units in this plan *(include a separate page 1 for each control unit)*

A. Unit ARP ID Number

B. Short Name

C. 1988-89 Average Emissions *(TPY)*

D. The unit is:

☐ 1. Appendix A

☐ 2. Substitution

☐ 3. Compensating

E. Projected Heat Input *(in mmBtu)*; Sulfur Dioxide Emissions Rate *(in lbs/mmBtu)* and Sulfur Dioxide Emissions *(in TPY)*

	1995	1996	1997	1998	1999
mmBtu					
lbs/mmBtu					
TPY					

	1995	1996	1997	1998	1999
F. Proposed Phase I Reserve Allowances Requested *(TPY)*:					
G. Proposed Total Allowance Allocation *(TPY)*:					
H. Available Transfer Capacity *(TPY)*:					

I. Qualifying Phase I Technology (90% Control Equipment):

1. Description of the Equipment:

a. Type of technology *(attach additional sheet if necessary)*: →

b. Design Sulfur Dioxide removal efficiency: →

c. Characteristics of the fuel and range of fuels for which the technology is designed *(attach additional sheets if necessary)*:

2. Schedules of Compliance:

a. Design Engineering *(mm/dd/yy)*:		b. Construction *(mm/dd/yy)*:		c. Operation *(mm/dd/yy)*:	
i. Start date		i. Start date		i. Start-up testing	
ii. Complete date		ii. Complete date		ii. Commence operation	

d. Control Equipment Maintenance Schedule:

e. Performance Test: Start Up Test *(mm/dd/yy)* →

J. Monitoring *(mark one)*:

☐ 1. This unit will monitor emissions in accordance with 40 CFR Section 75.12.

☐ 2. This unit will request approval for an alternative monitoring method for the determination of 90% control of Sulfur Dioxide because the above identified technology removes Sulfur Dioxide through a chemical reaction in the combustion process.

Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

II. TRANSFER UNITS

If more than 5 units, include copies of this page and enter number of copies here

	A. Unit ARP ID Number	B. Short Name	C. 1988-89 Average Emissions *(TPY)*
1			
2			
3			
4			
5			

D. Projected Heat Input *(mmBtu)*, Sulfur Dioxide Emissions Rate *(lbs/mmBtu)* and Sulfur Dioxide Emissions *(TPY)*

		1995	1996	1997	1998	1999
1	*mmBtu*					
	lbs/mmBtu					
	TPY					
		1995	1996	1997	1998	1999
2	*mmBtu*					
	lbs/mmBtu					
	TPY					
		1995	1996	1997	1998	1999
3	*mmBtu*					
	lbs/mmBtu					
	TPY					
		1995	1996	1997	1998	1999
4	*mmBtu*					
	lbs/mmBtu					
	TPY					
		1995	1996	1997	1998	1999
5	*mmBtu*					
	lbs/mmBtu					
	TPY					

	E. Proposed Phase I Extension Reserve Allowances Requested *(TPY)*:		F. Proposed Total Allowance Allocation *(TPY)*:				
	1995	1996	1995	1996	1997	1998	1999
1							
2							
3							
4							
5							

Enter totals in the unnumbered blocks at the bottom of each column

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

Please print or type in the unshaded areas only.

III. EMISSIONS TRANSFER RECONCILIATIONS

A. 1995 Reconciliation

If more than 5 transfer units, photocopy this sheet and enter the number of copies →

Transfer Unit	Control Unit				Total Emissions Being Transferred by Transfer Unit *(TPY)*
1					
2					
3					
4					
5					
Total Transfers to Control Units *(from this page)*					
Total Emissions Transferred *(from attachments)*					
Total Emissions Transferred					

B. 1996 Reconciliation

If more than 5 transfer units, photocopy this sheet and enter the number of copies →

Transfer Unit	Control Unit				Total Emissions Being Transferred by Transfer Unit *(TPY)*
1					
2					
3					
4					
5					
Total Transfers to Control Units *(from this page)*					
Total Emissions Transferred *(from attachments)*					
Total Emissions Transferred					

IV. RESERVE ALLOWANCE REQUEST

Total Phase I Extension Reserve Allowances requested for all control units and all transfer units governed by this proposed plan:	1995 - 1999

V. REQUIRED SUBMISSIONS

The following documents must accompany this application; if they do not, the Administrator will consider this application incomplete:

A. a copy of an executed contract for the design engineering and construction of the qualifying Phase I Technology for the control unit.

B. a certified vendor guarantee specifying the design Sulfur Dioxide removal efficiency and stating that the control unit technology will achieve at least 90% removal of Sulfur Dioxide for the type and range of fuels that will be used at the control unit.

VI. STANDARD PROVISIONS & PROHIBITIONS

A. Emissions Limitations

1. During the 2 year extension period and thereafter, the designated representative shall hold allowances in the Allowance Tracking System compliance subaccount for each affected unit governed by the plan by the allowance transfer deadline as provided for in 40 CFR Part 73, not less than the total annual sulfur dioxide emissions from the unit.
2. As provided for in Section 404(d)(7) of the Act, after January 1, 1997 no control unit or transfer unit shall emit sulfur dioxide in excess of the annual tonnage limitation specified in the Phase I Extension plan in Sections I.E. and II.D. of this form (for 1997-1999) as approved. Even if the designated representative holds allowances in the unit's Allowance Tracking System compliance subaccount to cover the unit's emissions for the year for purposes of 40 CFR Part 77, the Administrator shall deduct allowances equal to any exceedance of the extension plan limitation from the unit's annual allowance allocation in the following calendar year.
3. Beginning on the date the control unit is removed from operation to install the qualifying Phase I technology, each control unit governed by the extension plan shall comply with the applicable Phase I nitrogen oxides emissions limitation set forth in 40 CFR Part 76.
4. During the extension period and thereafter, each transfer unit governed by the extension plan shall comply with the applicable Phase I nitrogen oxides emissions limitation set forth in 40 CFR Part 76.

Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

VI. STANDARD PROVISIONS & PROHIBITIONS (cont.)

B. Test Methods

Each Phase I Extension plan shall include an emissions monitoring plan as required by 40 CFR Part 75 for each unit governed by the plan and a certification that continuous emissions monitoring systems are or not later than November 15, 1993 will be operational and certified by the Administrator on each Phase I extension control and transfer unit, as required by 40 CFR Part 75.

C. Recordkeeping Requirements

Records demonstrating compliance with the plan, including records demonstrating compliance with any performance standard or scheduled increment of progress throughout Phase I, must be maintained for a minimum of five years in accordance with Section 72.10. Such records shall include emissions monitoring records maintained in accordance with Part 72 and 40 CFR Part 75.

D. Reporting/Compliance Certification Requirements

1. The designated representative shall submit compliance certification reports for each affected source with a unit governed by the plan in accordance with subpart K of 40 CFR Part 72 evidencing each unit's compliance with the requirements of the plan.
2. The designated representative of each control unit shall submit the start-up performance test results and annual recertification test results or other approved test-method results with the quarterly emissions monitoring report for the quarter during which the test was conducted.

E. Prohibitions and Liability

1. It shall be a violation of the Act for any source or unit subject to an approved Phase I Extension plan under this section to operate in violation of the emissions limitation in Part VI.A., above.
2. The owners, operators, and the designated representatives of all control or transfer units shall be liable for any violation of the plan at any unit governed by the Phase I extension plan.
3. Failure to achieve 90% control during the 30-day start up test or annual recertification test shall be a violation of the Act.
4. In addition to the penalties that accrue as a result of any other liability under the Act, the Administrator shall withhold the allocation of Phase I extension allowances for any calendar year in which the unit fails to demonstrate by December 31 of that year that it has achieved 90% control.

VII. CERTIFICATIONS

I certify that I am the Designated Representative for the units that are the control units in the Phase I extension plan. I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*		
B. Signature	C. DR ID Number	D. Date Signed

I certify that I am the Designated Representative for the unit identified below that is a transfer unit in the attached Phase I extension plan. I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*	B. Unit ARP ID Number	
C. Signature	D. DR ID Number	E. Date Signed

FOR EPA USE ONLY

1. Date Received: ____________
2. Date of Initial Review: ____________ By: ____________
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: ____________
3. Date of Final Approval: ____________ By: ____________
4. Date Notice Sent: ____________ By: ____________

Comments: ____________

BILLING CODE 6560-50-C

7242A/pg.4

Phase I Acid Rain, Permit Program—Instructions for Form #7242

Forms #7242 and #7242A—Phase I Extension Plan

Introduction

Clean Air Act section 404(d) and the regulations implementing that Section at 40 CFR 72.42 allow the Designated Representative for a Phase I affected unit to petition for a two-year extension of the deadline for meeting Title IV emissions reduction requirements. To qualify for the extension, the affected until either must employ a Qualifying Phase I Technology (QPIT) or must transfer its Phase I emissions reduction obligation to a unit employing a QPIT. Units that transfer their emissions reduction obligations must be appendix A units. These forms allow an applicant to submit a proposed plan based on both of the options listed above for multiple control units at the same source.

Those who seek to qualify for a Phase I Extension plan and its attendant bonuses will participate in an early ranking procedure. As part of this procedure, the applicant will submit SF#7243, which is the Phase I Extension Early Ranking Application. Following the date of the ranking procedure, the applicant will submit SF#7243A, the Phase I Extension Plan. This form will confirm and, if necessary, correct the information provided in SF#7243, and includes enforceable provisions and prohibitions applicable to the participating units' Designated Representatives, owners and operators.

Phase I extension plans with transfer units may be filed jointly with affected units that have a different Designated Representative. The plan should be completed by the Designated Representative for the control unit or units, who will be responsible for distributing the plan proposal and for obtaining counter-signatures of each of the other Designated Representatives.

Instructions for Form 7242—Phase I Extension Early Ranking Application

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source. A number of sources may be included as part of the compliance plan. If more than one source is involved, you can save time by leaving the source number blank and completing the form through part IV. Then make sufficient copies of the plan for each source, fill in the appropriate source numbers, sign the form and circulate it as needed for additional signatures.

I. Control Unit

Control Unit Identification

A. Enter the unit's Acid Rain Program Identification Number found in appendix A or appendix B of 40 CFR part 72.

B. Enter the short time name from part I, section B of the unit application (SF#7231A).

C. Enter the 1988–89 Average Annual Emissions of Sulfur Dioxide, in TPY. This should be calculated using the information listed in appendices A or B, but may not exceed the annual TPY that would have resulted from application of the most stringent federally enforceable allowable emissions rate for those years.

D. For a non-appendix A unit that is serving as a control unit, indicate whether the unit will be brought into Phase I as a substitution unit in a substitution plan or as a compensating unit in a reduced utilization plan.

E. Control Unit Projections: For 1995 and 1996, enter the projected heat input (in mmBtu) and annual sulfur dioxide emissions rate (in lbs/mmBtu) that is the most stringent federally enforceable allowable limit at the time of application. Multiply these two numbers, divide by 2000 and enter the projected TPY.

For 1997, 1998, and 1999, enter the projected utilization in mmBtu as reported on DOE form 767 filed in the year of this application and the projected emissions rate (in lbs/mmBtu) with the qualifying Phase I technology operating at a sulfur dioxide removal efficiency of at least 90%. This rate may not exceed the most stringent federally enforceable allowable rate for sulfur dioxide at the time of application. Multiply these two numbers, divide by 2000, and enter result under TPY.

F. Enter the proposed Phase I Reserve Allowances requested for each year of Phase I. For the years 1995 and 1996, use the worksheet in Figure 1:

Figure 1: Worksheet for Calculation of Bonus Allowances

1. ________ (TPY)
2. ________ (TPY)
3. ________ (TPY)

1. Enter lesser of: the figure entered in part I C of the forms *or* the figure entered in part I E of the bottom of the column for the year (at TPY).

2. Compute 2 as follows: multiply the unit's baseline by 2.5, then divide by 2000.

3. Subtract figure in 2 from figure in 1 to get bonus allowances requested.

For the years 1997, 1998, and 1999, use the Worksheet in Figure 2:

Figure 2: Worksheet for Calculation of Bonus Allowance

1. ________ (TPY)
2. ________ (TPY)
3. ________ (TPY)

1. Multiply the unit's baseline by 1.2 and divide by 2000.

2. Enter figure entered in part I E of the form at the bottom of the column for the year.

3. Subtract 2 from 1; enter in appropriate year.

G. Enter the proposed total allowance allocation for each year of Phase I, calculated by adding together the reserve allowances for each year indicated in F above and the annual basic allocation in appendix A or B.

H. Enter the available capacity of this control unit to accommodate transfers of emissions reductions obligations from transfer units for the two years of the extension. This is calculated by subtracting the annual emissions in TPY that would be achieved at 90% control (as defined in ________) from the basic allowance allocation (or the allocation authorized under § 72.41 for a substitution unit in an approved substitution plan).

I. You must provide information for the Qualifying Phase I Technology (the 90% control equipment) for this control unit. Complete the following:

1. Describe the control equipment, including: a. the type of technology;

b. the sulfur dioxide removal efficiency of the design;

c. characteristics of the fuel and range of fuels for which the technology is designed.

For a and c, include additional sheets if necessary. If you use additional sheets, enter "see accompanying documents" in the space on the form.

2. The schedules of compliance including dates for the following increments of progress:

a. Design Engineering (start and complete date).

b. Construction (start and complete dates).

c. Operation (start-up testing and commence dates).

d. Provide a control equipment maintenance schedule.

e. Performance Test: Post Combustion Control Technology Start-Up Performance Test—this must be scheduled no later than 90 days after start up of post-combustion QPIT and must be consistent with the requirements of 40 CFR 75.12(c).

J. Monitoring. Mark the appropriate box to indicate the monitoring method.

a. Mark here if the unit will monitor with CEMS at both the outlet and the inlet of the control device in accordance with the requirements of 40 CFR 75.12:

b. Mark here if the unit will request approval for an alternative monitoring method. An alternative may be approvable if the control technology removes SO_2 through a chemical reaction in the combustion process.

II. Transfer Units

If there are no transfer units involved in this extension plan, put "Not Applicable" in the identification space provided for Transfer Unit Number 1. Otherwise, for each unit:

A. Enter the unit's Acid Rain Program Identification Number found at appendix A of 40 CFR part 72.

B. Enter the short name from Part I, Section B of the unit application.

C. Enter the 1988–89 Average Emissions of Sulfur Dioxide, in TPY. This should be calculated using the information filed on EIA form 767 and listed on Appendices A and B (SF# 7231A) and may not exceed the annual TPY that would have resulted from application of the most stringent federally-enforceable allowable emissions rate for those years.

D. Transfer Unit Projections: Enter the appropriate figures for each unit for heat input (in mmBtu), Sulfur Dioxide Emissions Rate (in lbs/mmBtu) and the Sulfur Dioxide Emissions (in TPY) for each year of Phase I: place the information in the spaces corresponding to the numbers in II A. Compute these figures as follows: [to be added, in part from § 72.43(e)]

E. For each transfer unit, enter the proposed Phase I Extension Reserve Allowances requested in TPY for 1995 and 1996 calculated as follows: [Note: insert text from 40 CFR 72.42(f)(3) (i) and (ii)] Compute

the totals for each year and enter on bottom line.

F. Enter the proposed total allowance allocation (in TPY) for units for each year of Phase I. This is calculated by adding the proposed reserve allowance for each unit to the basic allocation for that unit in Appendix A.

III. Emissions Transfer Reconciliations

In A and B, enter the proposed emissions to be transferred from the transfer units identified in this application including any attachments. This table will accommodate the transfer information for up to four control units and up to five transfer units. You should tabulate your results as follows:

• The total of the emissions being transferred by each transfer unit by adding horizontally along the line. This total should equal the number of reserve allowances requested for that unit;

• The total of the emissions being transferred by all transfer units to any one control unit by adding vertically down the column. This total should be less than or equal to the total transfer capacity of that control unit for that year (from I H of this form).

IV. Reserve Allowance Request

Enter the total Phase I reserve allowances requested for all control units and all transfer units governed by this plan for all years 1995–99 by adding together all the entries made in parts I F and II E of this form.

V. Required Submissions

You must attach include the following documentation with this submission or the plan will be considered incomplete:

• A copy of an executed contract for the design engineering and construction of the control equipment.

• A vendor guarantee stating that the technology will achieve at least 90% removal of sulfur dioxide emissions for the type or range of fuels that will be used at the control unit and specifying the design sulfur dioxide removal efficiency. In no event will such vendor guarantee constitute a defense to a unit's failure to achieve 90% control of sulfur dioxide emissions.

VI. Standard Provisions and Prohibitions

No entry is necessary, but you should read these provisions carefully.

VII. Certifications

The Designated Representative for the control unit is responsible for distributing the proposed plan to the Designated Representatives for all participating units, and for obtaining the signature for each Designated Representative.

The Designated Representative for the control unit must photocopy the entire form prior to signing it, making enough copies to distribute one each to the Designated Representative for each participating unit. The control unit Designated Representative then must sign all copies before distributing them to the Designated Representatives.

The Designated Representatives for the transfer units are responsible for reviewing the application for accuracy and for signing and returning a signed copy of the form to the Designated Representative for the control unit.

The proposed Designated Representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See part III, section A of the General Instructions for more information about the legal effect of certification.

Instructions for Form 7242A—Phase I Extension Plan

The instructions are the same as for Form 7242, above. Note, however, that the Standard Provisions and Prohibitions in part VI of the form are not the same.

BILLING CODE 6560-50-M

FORM 7243 AND 7243A

Reduced Utilization Plan

FORM 7243

Reduced Utilization Plan

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average ____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

FORM 7243A

Reduced Utilization Plan Verification

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average ____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

DRAFT 7243
Date 10/21/91
Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Reduced Utilization Compliance Plan
(Multiple Unit/Multiple Source)

Follow Instructions for Form 7243.

I. UNIT REDUCING UTILIZATION

A. Unit ARP ID Number

B. Short Name

C. Proposed Reductions in Utilization. *(Heat input in mmBtu; Generation in Kwh)*

	1995	1996	1997	1998	1999
mmBtu					
Kwh					

D. Proposed Annual Average Emission Rates *(lbs/mmBtu)*

	1995	1996	1997	1998	1999
SO_2					
NO_x					

E. This unit will account for its reduced utilization in the following ways:

- ☐ Phase I affected compensating unit(s) *(complete II.A., below)*
- ☐ Opt-in compensating unit(s) *(complete II.B., below)*
- ☐ Sulfur-free compensating installations *(complete II.C, below)*
- ☐ Energy conservation *(complete III, below)*
- ☐ Improved unit efficiency *(complete IV, below)*

II. COMPENSATING UNITS AND INSTALLATIONS

A. Phase I Affected Compensating Units

	1. Unit ARP ID Number	2. Short Name
1		
2		
3		

3. Compensating Generation *(Kwh)*

	1995	1996	1997	1998	1999
1					
2					
3					

B. Opt-in Compensating Units

	1. Unit ARP ID Number	2. Short Name
1		
2		
3		

3. Compensating Generation *(Kwh)*

	1995	1996	1997	1998	1999
1					
2					
3					

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

Please type or print in the unshaded areas only.

II. COMPENSATING UNITS AND INSTALLATIONS (cont.)

C. Sulfur-Free Compensating Installations

	1. AIRS Number	2. Short Name
1		
2		
3		

3. Compensating Generation *(Kwh)*

	1995	1996	1997	1998	1999
1					
2					
3					

D. Required Submissions

The following documents must accompany this plan; if they do not this plan will be incomplete:

1. For all plans designating a compensating unit of any kind:
   a. Documentation that demonstrates that the planned compensating generation will be provided by the units and/or installations identified in II.A., B., and C., above.
   b. Copies of completed Acid Rain Permit Applications (Forms XXXX & XXXX) and Certificates of Representation (Forms XXXX & XXXX) for all affected compensating units that are not located at the same source as the unit identified in Part I of this form.
2. For all plans designating an opt-in unit as a compensating unit, an opt-in plan pursuant to Part 74 for each unit identified in Part II.B. of this form.

III. ENERGY CONSERVATION

A. Description of Energy Conservation Measure(s)

1	
2	
3	

B. Implementation Schedule and Effective Life of Measure *(include additional sheets if necessary)*

1	
2	
3	

C. Energy conservation forecasts *(Energy Savings in Kwh; Heat Input Reduction in mmBtu)*

		1995	1996	1997	1998	1999
1	*Kwh*					
	mmBtu					
2	*Kwh*					
	mmBtu					
3	*Kwh*					
	mmBtu					

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

IV. IMPROVED UNIT EFFICIENCY

A. Description of Improved Unit Efficiency Measure(s)

1	
2	
3	

B. Implementation Schedule *(include additional sheets if necessary)*

1	
2	
3	

C. Unit efficiency forecasts *(Heat Rate Improvement in Btu/Kwh; Heat Input Reduction in mmBtu)*

		1995	1996	1997	1998	1999
1	*Btu/Kwh*					
	mmBtu					
2	*Btu/Kwh*					
	mmBtu					
3	*Btu/Kwh*					
	mmBtu					

V. ACCOUNTING OF REDUCED UTILIZATION

Year	A. Proposed Reduced Utilization	B. Projected Kwh Savings					C. Total
		IIA	IIB	IIC	III	IV	
1995							
1996							
1997							
1998							
1999							

VI. ACTIVATION AND TERMINATION OF PLAN

A. Activation

Choose one:

☐ 1. If approved, this plan will go into effect on *(mm/dd/yy)*: ______

☐ 2. The Designated Representative will notify the Administrator of activation of the approved plan.

B. Termination

This plan will remain in effect until *(mm/dd/yy)*: ——— ______

7243/pg.3

Source ARP ID Number

Please type or print in the unshaded areas only.

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

VII. STANDARD PROVISIONS AND PROHIBITIONS

A. Emissions Limitations
1. Each unit governed by this plan shall hold allowances in its Allowance Tracking System (ATS) compliance subaccount by the allowance transfer deadline that are not less than the unit's Sulfur Dioxide emissions for the calendar year.
2. Each Appendix A unit governed by this plan shall comply with the applicable Nitrogen Oxides emissions limitation of 40 CFR Part 76.

B. Monitoring Requirements
Each unit governed by this plan shall comply with the emissions monitoring plan and emissions monitor certification requirements of 40 CFR Section 72.31(c) and 40 CFR Part 75.

C. Recordkeeping Requirements
Each unit governed by the plan shall comply with the standard recordkeeping requirements of 40 CFR Parts 72-78, and shall maintain at the source all documents, verifications and demonstrations specified in this plan and in 40 CFR Section 72.43.

D. Reporting/Compliance Certification Requirements
1. Each unit governed by the plan shall submit compliance certifications in accordance with 40 CFR Sections 72.400-409.
2. The Designated Representative for each unit in a plan relying on energy conservation or improved unit efficiency measures shall submit annual verification of improved heat rate, reductions in heat input, and energy savings, as specified in 40 CFR Section 72.43(b)(6)(ii) and shall submit all reports required by 40 CFR Section 72.43(b)(6)(ii).
3. The Designated Representative of each unit relying on increased generation at a sulfur-free generation installation or a designated compensating source shall make the demonstration required by 40 CFR Section 72.43(b)(6)(iii).
4. The Designated Representative of the unit identified in Part I of this form shall account for all underutilization at the unit not contemplated by this reduced utilization plan as required by 40 CFR Sections 72.43, 72.402 and 72.409.

E. Prohibitions and Liability
1. It shall be a violation of the Act for the owners, operators, and Designated Representative of any affected unit governed by a reduced utilization plan to operate any such unit except in accordance with the terms of the plan as approved by the Administrator pursuant to this section or to fail to carry out any measure provided for in the plan.
2. It shall be a violation of the Act for any affected source or unit to emit Sulfur Dioxide or Nitrogen Oxides in excess of the emissions limitations provided for in the approved reduced utilization plan unless, in the case of Sulfur Dioxide, the unit has allowances in its ATS compliance subaccount by the allowance transfer deadline not less than the unit's total annual emissions for the year.
3. It shall be a violation of the Act for the owners, operators, and Designated Representative of any Phase I unit that reduces utilization in any calendar year in order to comply with the unit's Phase I emissions reduction obligations under the Acid Rain program to fail to submit a reduced utilization plan in accordance with 40 CFR Section 72.43.
4. The owners, operators, and Designated Representatives of any affected unit named in a reduced utilization plan approved by the Administrator shall be liable for any violation of 40 CFR Part 72 or of the reduced utilization plan.

VIII. CERTIFICATIONS

I certify that I am the designated representative for the unit identified below that is the unit reducing utilization in this reduced utilization plan. I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*	B. Unit ARP ID Number	
C. Signature	D. DR ID Number	E. Date Signed

I certify that I am the designated representative for the unit identified below that is part of the reduced utilization plan. I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*	B. Unit ARP ID Number	
C. Signature	D. DR ID Number	E. Date Signed

FOR EPA USE ONLY

1. Date Received: ____________
2. Date of Initial Review: ____________ By: ____________
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: ____________
3. Date of Final Approval: ____________ By: ____________
4. Date Notice Sent: ____________ By: ____________

Comments:

7243/pg.4

DRAFT 7243A
Date 10/21/91
Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Reduced Utilization Plan Verification
(End of Year Report)

Follow Instructions for Form 7243A.

I. UNIT IDENTIFICATION

A. Unit ARP ID Number	B. Short Name	C. Reporting Year

D. This unit is reporting the results of reduced utilization through:

☐ 1. Conservation Measures/Improved Unit Efficiency *(complete II.A., below)*

☐ 2. Compensating Generation (compensating units or sulfur-free installations) *(complete II.B., below)*

II. VERIFICATIONS

A. Conservation Measures/Improved Unit Efficiency

The following are the improved heat rate *(in Btu/Kwh, if applicable)*, reductions in heat input *(in mmBtu)*, and energy savings *(in Kwh)* at this unit for the:

	Btu/Kwh	mmBtu	Kwh
1. First Three Quarters (1/1 - 9/30)			
2. Fourth Quarter (10/1 - 12/31) *(estimated)*			

B. Compensating Generation

1. Designated Compensating Units:

	a. Unit ARP ID Number	b. Short Name
1		
2		
3		

	c. Previous Year Information → ____ *(Year)*		d. Gross Reporting Period Information		e. Net Reporting Period Information	
	Heat Input *(mmBtu)*	Generation *(Kwh)*	Heat Input *(mmBtu)*	Generation *(Kwh)*	Heat Input *(mmBtu)*	Generation *(Kwh)*
1						
2						
3						

2. Sulfur-Free Installations:

	a. AIRS Number	b. Short Name
1		
2		
3		

	c. Previous Year Information → ____ *(Year)*	d. Gross Reporting Period Information	e. Net Reporting Period Information
	Generation *(Kwh)*	Generation *(Kwh)*	Generation *(Kwh)*
1			
2			
3			

Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

III. REQUIRED SUBMISSIONS

The following documents must accompany this verification report; if not, this report will be incomplete.

A. The report of an independent auditor that verifies the figures listed in Part II.A. of this form; or,

B. Verification of the figures listed in Part II.A. of this form, certified by the utility regulatory authority of the State in which the unit is located.

IV. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative

B. Signature

C. Date Signed

FOR EPA USE ONLY

1. Date Received: ____________
2. Date of Initial Review: ____________ By: ____________
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: ____________
3. Date of Final Approval: ____________ By: ____________
4. Date Notice Sent: ____________ By: ____________

Comments:

BILLING CODE 6560-50-C

7243A/pg.4

Phase I Acid Rain Permit Program—Instructions for Form #7243

Forms 7243 and 7243A—Reduced Utilization Plan Forms

Introduction

Clean Air Act section 408(c) and the regulations implementing that Section at 40 CFR 72.43 require that a Phase I affected unit that projects reduced utilization at any time during Phase I must file a reduced utilization plan. Reduced utilization is defined as utilization of the unit that results in heat input of less than the unit's heat input baseline. In addition, a unit may file a reduced utilization plan that the unit can decide to activate during Phase I in the event that reduced utilization becomes a necessary or desirable compliance option. Those units with activated plans are required to submit end of year verifications.

A Designated Representative must submit a separate plan for each unit under his or her control that projects reduced utilization. In the plan, the Designated Representative may designate the following kinds of electrical generating facilities to compensate for the reduced utilization:

• Phase I affected units (from appendix B).

• Opt-in or new units.

• Sulfur-free generating installations (*e.g.*, nuclear or hydroelectric plants).

In addition, the Designated Representative may account for planned reduced utilization by forecasting energy savings that will result from energy conservation measures or improved unit efficiency measures.

Form #7243 is designed to allow the Designated Representative to supply information about any of the options chosen to explain the reduced utilization. In addition, the form provides a space for tabulating all of the utilization projections for the options, so that the applicant can determine whether the plan as formulated meets the requirement to account for the projected reduction in utilization. The Designated Representative may file a reduced utilization plan at any time during Phase I.

The compensating units included in the plan may have different Designated Representatives than the original unit. The plan should be completed by the Designated Representative for the unit reducing utilization, who will be responsible for distributing the plan proposal and for obtaining the counter-signatures of each of the other Designated Representatives.

At the end of each year that the plan is in effect the Designated Representative must submit SF# 7243A, to verify that the reduced utilization accounting in the plan was achieved during the year. The results from this report must be included in the Annual Compliance Certification Report (SF# 72402). The deadline for filing SF# 7243A is January 30, the due date for the Annual Compliance Certification Report. If that accounting was not achieved, the Designated Representative must comply with the requirements of 40 CFR 72.409 by filing SF# 72409 and SF# 72409A, as applicable.

Instructions for Form 7243—Reduced Utilization Plan

I. Unit Identification.

A. Enter the unit's Acid Rain Program Identification Number, found in appendix A of 40 CFR part 72.

B. Enter the short name for the unit given in the unit permit application at part I, section B (SF# 7231A).

C. Indicate the proposed reduced utilization (in both heat input and energy savings) for the unit during each year of Phase I. For any years that no reduced utilization is projected, enter "Not Applicable" ("N/A").

D. Provide the proposed annual average emissions rates (in lbs/mmBtu) for the unit for each year of Phase I.

E. Indicate how the unit will account for its reduced utilization. Mark all that are applicable, and complete the appropriate sections of the form.

II. Compensating Units and Installations

A. Affected Compensating Units: Identify all affected units that will provide compensating generation for the original unit.

1 and 2. Provide the Acid Rain Program Identification Number and short name (see instructions at I A and B, above).

3. Enter the compensating generation for the units listed for each year of Phase I that reduced utilization is projected.

B. Opt-in Units: 1 and 2. Provide the Acid Rain Program Identification Number and short name.

3. Enter the compensating generation for the units listed for each year of Phase I that reduced utilization is projected.

C. Sulfur-Free Compensating Installations: Identify any electrical generating installations that do not emit sulfur dioxide that will be used to provide compensating generation for the original unit.

1. Enter the AIRS number for the facility, available from [to be added].

2. Enter the name of the facility.

D. If compensating generation is provided from a unit or installation in another system, indicate by checking the boxes that you have attached the required documentation, including utility system directories or power purchase/other contracted agreement governing compensating generation.

III. Energy Conservation

A. Describe the Energy Conservation measures that will be used at the original unit to account for the reduced utilization at the original unit.

B. Provide the implementation schedule for and effective life of each measure, as follows: [to be added]

C. For each measure identified, indicate the energy savings, heat rate improvement and heat in reductions forecast for each year of the plan. Enter "Not Applicable" ("N/A") for those years in which either there is no reduced utilization projected or the conservation measure will not be in effect.

IV. Improved Unit Efficiency Measures

A. Describe the improved unit efficiency measures that will be used at the original unit to account for reduced utilization at the original unit.

B. Provide the implementation schedule for each measure, as follows: [to be added]

C. For each measure identified, indicate the energy savings, heat rate improvement and heat input reductions forecast for each year of the plan. Put "Not Applicable" ("N/A") for those years in which either there is no reduced utilization projected or the efficiency measure will not be in effect.

V. Accounting of Reduced Utilization

A. Enter the proposed energy savings reductions (in kwh) from Part I C of this form for each year that is applicable.

B. For each year of proposed reduced utilization, enter the projected kwh accounted for by the options listed in the form. Enter the information in the spaces corresponding to parts of the form (*e.g.*, in II A, list the projected kwh to be compensated for by a Phase I affected compensating unit, which is found at Part II A at 3).

C. Add across the line and enter totals for each year.

VI. Activation and Termination of Plan

A. Indicate either:

• That the plan, if approved, will go into effect on a date certain (enter the date); or

• That the Designated Representative will notify the Administrator of activation of the approved plan.

B. Enter the date on which the plan will terminate.

VII. Standard Provisions and Prohibitions

No entry is required, but you should read these provisions carefully.

VIII. Certifications

The Designated Representative for the original unit is responsible for distributing the proposed plan to the Designated Representatives for all participating units, and for obtaining the signature for each Designated Representative.

The Designated Representative for the original unit must photocopy the entire form prior to signing it, making enough copies to distribute one each to the Designated Representative for each participating unit. He or she then must sign each copy before distributing them to the Designated Representatives.

The Designated Representatives for the compensating units are responsible for reviewing the application for accuracy, for signing and returning the form to the Designated Representative for the original unit, and for including a copy of the form with the permit application for the compensating unit.

All Designated Representatives who sign this form thereby certify to the truth, accuracy and completeness of the information provided in the form. See Part III, Section A of the Forms Instructions Package for more information about the legal effect of certification.

Instructions for Form 7243A—Reduced Utilization Plan Verification (End of Year Report)

I. Unit Identification

A. Enter the unit's Acid Rain Program Identification Number, found in appendix A of 40 CFR part 72.

B. Enter the short name for the unit given in the unit permit application at part I, section B (SF# 7231A).

C. Enter the year for which this report is submitted (*i.e.*, the reporting year).

D. Indicate the parts of the reduced utilization plan that will be verified by this submission. You may check either or both of the boxes.

II. Verifications

A. Conservation/Improved Unit Efficiency: 1. Provide the improvement in heat rate (in Btu/kwh), reductions in heat input (in mmBtu), and energy savings (in kwh) achieved at the unit between January 1 and September 30 of the reporting year. Heat rate improvement figures are only needed when reporting on improved unit efficiency.

2. Provide an estimate of the improved heat rate, reductions in heat input and energy savings for the 4th quarter of the reporting year (October 1—December 31). This estimate should be based on the verified savings provided in II A 1 above. Heat rate improvement figures are only needed when reporting on improved unit efficiency.

B. Compensating Generation: 1. If the reduced utilization plan listed Designated Compensating units (units that were identified in the plan on SF#7243 at parts II A and II B), provide a and b. The identifying information supplied in SF#7243.

c. Heat input (in mmBtu) and generation (in kwh) information for the year prior to this reporting year. For the 1995 report, this figure should be reported here as reported on EIA form 767 for 1994. For the years 1996–1999, this figure will be the figure entered on the previous year report at part II B 1 (d).

d. Gross Reporting Period Information, as reported on emissions monitoring quarterly reports.

e. Net Reporting Period Information, calculated as follows: net annual heat input or kwh = gross annual heat input − [(percent growth in kwh sales from previous year) × gross annual heat input].

2. If the Reduced Utilization plan designated sulfur-free installations for compensating generation, provide:

a and b. The identifying information supplied in Form 7243.

c. Generation (in kwh) information for the year prior to this reporting year. For the 1995 report, this figure will be as reported on EIA forms 767, 759 or 867 for 1994. For the years 1996–1999, this figure will be the figure entered in on the previous year report at part II B 1 (d).

d. Gross Reporting Period Information, which will be self reported.

e. Net Reporting Period information, calculated as follows: net annual kwh = gross kwh − [(% of growth in kwh sales from previous year) × gross kwh].

III. Required Submissions

You must attach one of the following or the verification form will be considered incomplete:

- The report of an independent auditor that verifies the figures listed in A1 by using the procedures set forth in the EPA Conservation Verification Protocol, to 40 CFR 73.81(a); or
- If the unit is subject to the jurisdiction of a state regulatory authority, the state authority may verify demand-side measures if the authority meets the least cost planning (LCP) and net income neutrality (NIN) criteria set forth at 40 CFR part 73 and the authority may verify supply-side measures regardless of whether that authority meets the LCP and NIN criteria of 40 CFR part 73.

If the state authority verification process would interfere with a unit's ability to meet the compliance certification deadlines (*i.e.*, January 30 for this form, March 30 for 4th Quarter savings verification), then the verification report shall be made by an independent auditor as described above.

IV. Certification

The Designated Representative for the original unit is responsible for distributing a copy of the completed form to the Designated Representatives for all participating units.

The Designated Representative who signs this form thereby certifies to the truth, accuracy and completeness of the information provided in the form. See part III, section A of the General Instructions for more information about the legal effect of certification.

BILLING CODE 6560-50-M

FORM 7246

NO_x Emissions Averaging Plan

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

PHASE I ACID RAIN PERMIT PROGRAM
INSTRUCTIONS FOR FORM #7246

FORM #7246
NO_x EMISSIONS AVERAGING PLAN

[to be included in draft of Part 76 regulations]

FORMS 7247 AND 7247A

NO_x Alternative Emissions Limitation Proposal

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

PHASE I ACID RAIN PERMIT PROGRAM
INSTRUCTIONS FOR FORM #7247 AND 7247A

FORM #7247 AND 7247A
NO_x ALTERNATIVE EMISSIONS LIMITATION PROPOSAL

[to be included in draft of Part 76 regulations]

EPA Form xxxx

FORM 7248

NO_x Deadline Extension

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

PHASE I ACID RAIN PERMIT PROGRAM
INSTRUCTIONS FOR FORM #7248

FORM #7248
NO_x DEADLINE EXTENSION

[to be included in draft of Part 76 regulations]

EPA Form xxxx

FORM 72402

Annual Compliance Certification Report

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average ____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

DRAFT 72402
Date 10/21/91
Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Annual Compliance Certification Report

Follow Instructions for Form 72402.

I. GENERAL INFORMATION

A. Unit ARP ID Number	B. Short Name	C. Reporting Year

D. Mark all activated compliance plans:

- ☐ 1. Substitution
- ☐ 2. Phase I Sulfur Dioxide Extension
- ☐ 3. Reduced Utilization
- ☐ 4. Nitrogen Oxides Emissions Averaging
- ☐ 5. Nitrogen Oxides Alternative Emissions Limits
- ☐ 6. Nitrogen Oxides Compliance Deadline Extension
- ☐ 7. Common Stack

II. REPORTING UNIT COMPLIANCE CERTIFICATIONS

A. Sulfur Dioxide

1. Emissions and Allowance Information

a. Total Tons of Sulfur Dioxide Emitted by the Unit:	b. Number of Allowances in the Unit Compliance Year Subaccount by the Compliance Transfer Deadline:

2. Emissions Certification *(choose one):*

☐ a. I certify that the Sulfur Dioxide emissions at this unit did not exceed allowances held for this unit for use during the year of this report, as shown by the above information.

☐ b. I certify that the Sulfur Dioxide emissions at this unit did exceed allowances held for this unit for use during the year of this report, as shown by the above information.

3. Utilization Information. Heat Input *(in mmBtu)*; Generation *(in Kwh)*:

a. Baseline Period Information		b. Reporting Period Information		c. Underutilization	
mmBtu	Kwh	mmBtu	Kwh	mmBtu	Kwh

4. Utilization Certifications

☐ a. I certify that this unit did not have underutilization as shown by the information listed in II.A.3., above.

☐ b. I certify that the underutilization reported in II.A.3.c., above, can be accounted for as follows:

	mmBtu	Kwh
☐ i. The following underutilization was due to shifts within the Phase I utility system and is accounted for by the aggregate of Phase I affected units in the utility system of which this unit is a part, as reported in Form #XXXX: →		
☐ ii. The following underutilization was due to a calendar year sales decrease for the utility system of which this unit is a part, as reported on Form #XXXX: →		
☐ iii. The following underutilization was due to the planned reductions in accordance with 40 CFR Section 72.43 as reported on Form #XXXX, including:		
☐ A. Conservation/improved unit efficiency →		
☐ B. Compensating unit/sulfur-free generation designated in the reduced utilization compliance plan →		
Total Accounted For:		
Balance of Utilization Below Baseline:		

☐ iv. The balance of underutilization was due to dispatching within the unit's system and is accounted for by the aggregate of non-Phase I affected units in systems of which this unit is a part; this submission includes Form #XXXX, which calculates the allowance deduction corresponding to this balance.

Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

II. REPORTING UNIT COMPLIANCE CERTIFICATIONS (cont.)

☐ c. I certify that this unit had underutilization caused by a forced outage as reported in Form #XXXX, and that

☐ i. this unit has accounted for the underutilization by the demonstration in II.A.4.b., above.

☐ ii. this forced outage will be permanent or prolonged and I herewith submit a compliance plan in accordance with 40 CFR Section 72.43 that designates a compensating unit or installation.

d. I certify that the allowances held in the unit's compliance subaccount as of the allowance transfer deadline:

☐ i. are equal to or greater than the following emissions *(in TPY)* that would have occurred but for the underutilization balance:

☐ ii. are less than the following emissions *(in TPY)* that would have occurred but for the underutilization balance:

TPY

B. Nitrogen Oxides

1. Emissions Limit/Emissions Rate Information:

a. Annual Average Nitrogen Oxide Emissions Rate *(lbs/mmBtu)*	b. Nitrogen Oxide Emissions Limitation *(lbs/mmBtu)*

2. Emissions Certification *(choose one)*:

☐ a. I certify that the Nitrogen Oxide emissions at this unit did not exceed the allowable emissions limitation for this unit for use during the year of this report, as shown by the above information.

☐ b. I certify that the Nitrogen Oxide emissions at this unit did exceed the allowable emissions limitation for this unit for the year of this report, as shown by the above information.

III. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*

B. Signature

C. Date Signed

FOR EPA USE ONLY

1. Date Received: ____________
2. Date of Initial Review: ____________ By: ____________
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: ____________
3. Date of Final Approval: ____________ By: ____________
4. Date Notice Sent: ____________ By: ____________

Comments:

BILLING CODE 6560-50-C

Phase I Acid Rain Permit Program—Instructions for Form 72402

Form #72402 Annual Compliance Certification Report

Introduction

Clean Air Act section 412 and the regulations implementing that Section at 40 CFR 72.402 require the Designated Representative for each affected unit to submit annual compliance certifications for the unit. This certification will indicate whether the unit met the sulfur dioxide and nitrogen oxides emissions limitations for that compliance year. Units that fail to meet these limitations also must file excess emission offset plans (for exceedances of sulfur dioxide limitations) and excess emissions penalty forms for both pollutants of concern. The form also will indicate whether the unit has any under-utilization and, if so, whether it has accounted for it properly.

Annual compliance certifications must be postmarked no later than January 30, the compliance transfer deadline established pursuant to Part 73.

Instructions

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. General Information

A. Enter the unit Acid Rain Program Identification Number.

B. Enter the short name for the unit.

C. Enter the calendar year for which the report is submitted.

D. Compliance Plans

Indicate all currently activated compliance plans in which this unit participated during the reporting year indicated in A above.

II. Reporting Unit Compliance Certifications

A. Sulfur Dioxide: 1. Emissions and Allowance Information:

a. Enter tons of sulfur dioxide emitted during the reporting year.

b. Enter the number of allowances in the unit compliance sub-account or submitted to EPA for recordation by the compliance transfer deadline.

2. The Designated Representative should certify whether the unit was in compliance with sulfur dioxide limitations, by marking the appropriate box.

3. Utilization Information: a. For the baseline period, enter the heat input (from Appendix A or B (in mmBtu)), and the generation (in kwh).

b. For the Reporting Year, enter the heat input and generation as reported on emissions monitoring quarterly reports.

c. Enter the under-utilization (subtract figures in b from corresponding figures in a; if the results is zero or a negative number, enter 0 (zero)).

3. Utilization Certifications: Choose a, b, c or d.

a. Mark this box if the unit did not have under-utilization.

b. Indicate by marking the appropriate box(es) which of the options listed in i–iv explains the under-utilization, and supply the utilization figures for the amount of under-utilization accounted for by each option from the applicable reporting form.

c. If a forced outage caused the under-utilization indicate one or both of the following:

(i) That the unit can account for the under-utilization by using a demonstration from II A 3 b, above; and/or,

(ii) That the duration of the outage will trigger the requirement to submit a plan pursuant to 40 CFR 72.43 and that you have submitted the plan.

d. Mark the box that indicates whether you can demonstrate that there were sufficient allowances in the unit's compliance subaccount to account for the emissions that would have occurred but for the under-utilization balance, and enter the sulfur dioxide emissions that would have occurred but for the under-utilization balance, calculated as follows: [to be added].

B. Nitrogen Oxides: 1. Emissions information:

a. Enter the applicable nitrogen oxides emissions limit.

b. Enter the annual average emissions rate for the reporting year.

2. The Designated Representative should certify whether the unit was or was not in compliance with the nitrogen oxides emission limitation, by marking the appropriate box.

IV. Certification

The Designated Representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See Part III, Section A of the Forms Instructions Package for more information about the legal effect of certification.

BILLING CODE 6560-50-M

FORMS 72409 AND 72409A

Utilization and Forced Outage Reports

Form 72409

Utilization Report

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

Form 72409A

Forced Outage Report

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

DRAFT 72409
Date 10/21/91
Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Underutilization Report

Follow Instructions for Form 72409.

I. UNIT IDENTIFICATION

A. Unit ARP ID Number	B. Short Name

II. EXPLANATION OF UNDERUTILIZATION

The underutilization reported on the annual compliance certification form is explained as follows:

A. Demonstration of Shift in Generation to Other Phase I Affected Units

1. Aggregate Utilization of Phase I Units for Reporting Year		2. Aggregate Baseline of Phase I Units	
Kwh		Kwh	
mmBtu		mmBtu	
3. Amount of underutilization at the unit not attributable to shifts in generation to other Phase I units in the system. →		Kwh	
		mmBtu	

B. Demonstration of System Wide Decrease in Electrical Demand

1. Percentage decline in aggregate annual kilowatt hour sales for the utility system in the reporting year compared to system sales during the preceding calendar year *(%)* →

2. Decline in Utilization of the Unit Attributable to the System Wide Decline		3. Amount of Underutilization at the Unit not Attributable to the System Wide Decline	
Kwh		Kwh	
mmBtu		mmBtu	

III. ALLOWANCE DEDUCTIONS FOR UNPLANNED UNDERUTILIZATION

Enter the following figures:

A. Net aggregate underutilization at all Phase I units in the utility system below the aggregate baseline for all affected units in the utility system *(mmBtu)* →

B. Utility system gross underutilization *(mmBtu)* →

C. Utilization below baseline for the reporting unit *(mmBtu)* →

D. Btu-weighted average annual emissions rate for the previous calendar year for either: (1) all units in the NERC region where the underutilized unit is located; or (2) all units within the utility system and units outside the utility system that have been specifically identified *(lbs/mmBtu)* →

E. Aggregate underutilization at all Phase I units in the utility system below their aggregate baseline that is attributable to the system-wide percentage decline in utilization *(mmBtu)* →

F. The percentage of the total annual BTUs above baseline that is attributable to Phase I units located in the NERC region where the unit that experienced the underutilization is located →

Calculate the allowances to be surrendered, according to the following formula:

$$\frac{(A\text{-}E)\text{-}((A\text{-}E)xF)x(C/B)xD}{2000}$$ → Enter Result:

IV. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative

B. Signature	C. Date Signed

Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

FOR EPA USE ONLY

1. Date Received: ______
2. Date of Initial Review: ______ By: ______
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: ______
3. Date of Final Approval: ______ By: ______
4. Date Notice Sent: ______ By: ______

Comments: ______

DRAFT 72409A
Date 10/21/91
Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Forced Outage Report

Follow Instructions for Form 72409A.

I. UNIT IDENTIFICATION

A. Unit ARP ID Number

B. Short Name

☐ Attached is a copy of the notice sent to EPA within 72 hours of the occurrence.

II. OUTAGE INFORMATION

A. Events Responsible for Forced Outage *(include additional sheets if necessary)*:

B. Duration of Outage

1. Commencement

This outage began on *(mm/dd/yy)*

2. Termination *(complete a, b, or c)*

☐ a. The outage ended and the unit returned to service on *(mm/dd/yy)*:

☐ b. The outage is expected to end and the unit will return to normal service on *(mm/dd/yy)*:

☐ c. The outage will continue in the next calendar year and will cause the unit to transfer generation permanently to units not otherwise affected during Phase I *(see instructions)*.

C. Corrective Measures

The Unit operator has taken or plans to take the following measures to correct this outage *(include additional sheets if necessary)*: Measures *(describe)*:	Completion Date *mm/dd/yy*

D. Underutilization Attributable to the Forced Outage: →	mmBtu	Kwh

The underutilization is accounted for on Form #XXXX by the following methods:

☐ 1. Other Phase I Units

☐ 2. System wide downturn

☐ 3. Energy conservation

☐ 4. Improved unit efficiency

☐ 5. Compensating generation

☐ 6. Non-Phase I affected system

III. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative

B. Signature

C. Date Signed

Please type or print in the unshaded areas only.

Source ARP ID Number										

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

FOR EPA USE ONLY

1. Date Received: ______
2. Date of Initial Review: ______ By: ______
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: ______
3. Date of Final Approval: ______ By: ______
4. Date Notice Sent: ______ By: ______

Comments: ______

BILLING CODE 6560-50-C

72409A/pg. 2

Phase I Acid Rain Permit Program Instructions for Forms #72409 and #72409A

Forms #72409 and #72409A Utilization and Forced Outage Reports

Introduction

Clean Air Act § 412 and the regulations implementing that Section at 40 CFR § 72.400–409 require the Designated Representative for each affected unit to submit annual compliance certifications for the unit. This certification must report any underutilization at the unit, and must account for that underutilization. Section 72.409 provides the details of the accounting process, which permits the Designated Representative to demonstrate that the underutilization was due to any of three causes;

• System-wide decrease in electrical demand;

• Shift in generation to above Phase I units in the same system; or

• A forced outage.

Form 72409A allows the Designated Representative to report on a forced outage, while SF# 72409 allows the Designated Representative to make demonstrations of the first two causes listed above.

Annual compliance certifications must be postmarked no later than *(to be added)*, the compliance transfer deadline established pursuant to Part 73.

Instructions for Form #72409—Utilization Report

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. Unit Identification

A. Enter the unit Acid Rain Program Identification Number.

B. Enter the short name for the unit.

II. Explanation of Under-Utilization

In these two parts, enter the information that will account in whole or in part for the under-utilization at the reporting unit.

A. Demonstration of Shift in Generation to Other Phase I Affected Units: 1. Calculate the aggregate utilization (in mmBtu and kwh) of all Phase I affected units within the utility system identified in the permit application for this unit by summing the utilization for all of those units. Enter the results.

2. Calculate the aggregate baseline and related generation figures for the baseline period of all Phase I units within the system by summing the baselines and related generation figures for all those units and enter the result.

3. Enter the result of subtracting the figures entered at 1 from the figures entered at 2. If the result is zero or a negative number, enter 0. In that event, you have accounted for all underutilization and need to make no further demonstration. If the result is positive, and if the underutilization is not accounted for by a forced outage (on SF# 72409A), you may complete part II B if applicable, or go directly to Part III to calculate allowance deductions.

B. Demonstration of System Wide Decrease in Electrical Demand: 1. Calculate the percentage decline of aggregate reporting-year kilowatt hours sales for the utility system identified in the unit's permit application as compared to system wide sales during the preceding calendar year, as follows: [(Kwh sales for previous year—Kwh sales for reporting year) + Kwh sales for the previous year] and enter result.

2. Calculate the decline in utilization of each Phase I unit, in kwh and mmBtu, as compared to baseline that is attributable to the system wide percentage decline in utilization as follows: [decline in sales x baseline for each Phase I unit with under-utilization] and enter.

3. Enter the result of subtracting the figures in II B 2 from the balance remaining at II A 3, above. If the result is zero or a negative number, enter 0 (zero). In that event, you have accounted for all underutilization and need make no further demonstration. If the result is positive, and if the under-utilization is not accounted for by a forced outage (on SF# 72409A), complete part III, below.

III. Allowance Deductions for Unplanned Under-Utilization

In the event there is remaining under-utilization, you must calculate the allowances that will be deducted from the unit's compliance subaccount for the following year. These deductions are intended to account for increased emissions at the unaffected units that presumptively supplied compensating generation.

To calculate the allowances to be surrendered, use the formula shown in the application.

"A" is the "net aggregate under-utilization" at all Phase I units in the utility system below the aggregate baseline for all affected units in the utility system (in mmBtu), calculated by subtracting the gross under-utilization "B" from the aggregate utilization above baseline (in mmBtu) of all Phase I units in the system operated above baseline;

"B" is the utility system gross under-utilization (in mmBtu), calculated by adding the aggregate utilization below baseline for all affected units within the system;

"C" is the utilization below baseline for the individual affected unit for which the calculation is being made (in mmBtu);

"D" is the Btu-weighted average annual emissions rate for the previous calendar year for either: (1) All units in the NERC region where the under-utilized unit is located; or (2) all units within the utility system and units outside of the utility system that have been specifically identified.

"E" is the aggregate under-utilization at all Phase I units in the utility system below their aggregate baseline that is attributable to the system-wide percentage decline in utilization, as calculated pursuant to § 72. 409(b)(1); and

"F" is the percentage of the total annual Btu's above baseline that is attributable to Phase I units located in the NERC region where the unit that experienced the under-utilization is located, multiplied by the percentage of the utility's generation from units outside of the utility system that have not been specifically identified if using formula (ii), below;

To calculate "D", use one of the following formulas:

(i) To calculate the NERC Region or sub-region average emissions rate:

[Formula will be added from 40 CFR 72.409]

(ii) To calculate the average emissions rate for the utility system and for any other units outside of the system for which the utility can document it has received generation:

[Formula will be added from 40 CFR 72.409]

where:

"a_i" is the difference between the annual heat input for each unit within the NERC region (in mmBtu) and the baseline for each unit within the NERC region (in mmBtu).

"b_i" is the average annual emissions rate for each unit within the NERC region in lbs/mmBtu.

"c_i" is the difference between the annual heat input for each unit within the utility system and each specifically identified unit outside of the utility system (in mmBtu) and the baseline for each unit within the utility system and each specifically identified unit outside of the utility system (in mmBtu).

"d_i" is the average annual emissions rate for each unit within the utility system and each specifically identified unit outside of the utility system.

"e" is the % of generation from units outside of the utility system that have not been specifically identified.

"f" is the % of generation from units within the utility system and units outside of the utility system that have been specifically identified.

"n" is the number of units in the NERC region.

"m" is the number of units in the utility system and specifically identified units outside the system providing compensating generation.

IV. Certification

The Designated Representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See Part III, Section A of the Forms Instruction Package for more information about the legal effect of certification.

Instructions for Form 72049A—Forced Outage Report

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. Unit Identification

A. Enter the unit Acid Rain Program Identification Number.

B. Enter the short name for the unit.

Check the box and attach a copy of the notice of the forced outage that was sent to EPA.

II. Outage Information

A. Describe the event or events that were responsible for the forced outage, *e.g.*, turbine failure.

B. Indicate the actual or anticipated duration of the outage by:

1. Entering the day the outage began:

2. a. If the outage is over, enter the date the unit returned to full service; or,

b. If the outage is continuing, but expected to end, enter the anticipated date of return to full service; or,

c. If the outage will continue into the following calendar year and the designated

representative anticipates that the outage will cause the unit permanently to transfer generation to one or more units that are not otherwise affected during Phase I, you must either

•–Request a permit revision by submitting a reduced utilization plan designating one or more compensating units; or

•–Submit a demonstration that it is not possible to restore the unit to service at a reasonable cost. This demonstration can be a utility rate regulatory authority determination or [*to be added*].

C. Describe the corrective measures the unit operator has taken or will take to correct this outage, including the actual or anticipated date that the measure will be completed or in place. If additional sheets are necessary for a full description, please enter "see accompanying *(#)* page report" in the space provided.

D. Under-utilization Accounting

Enter the under-utilization attributable to the forced outage.

Indicate by marking the appropriate boxes how the unit will account for the underutilization caused by the forced outage. The under-utilization accounting information will be entered on SF× 72409.

III. Certification

The Designated Representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See part III, section A of the Forms Instruction Package for more information about the legal effect of certification

Form 7251—Draft Phase I Acid Rain Permit

U.S. Environmental Protection Agency Office of Atmosphere and Indoor Air Pollution Acid Rain Division

Phase I Acid Rain Permit

(Note: Items in brackets indicate where EPA will fill in source-specific information. Provisions in the draft permit will be consistent with the final version of 40 CFR Part 72.54)

The U.S. EPA issues this Permit to:

[Source Name]
[Street Address]
[City, State, Zip]

in the following NERC region or Sub-Region

[NERC region or Sub-Region]

This permit governs the following affected units located at this source:

[Unit Name and Acid Rain Program Identification Number]
[Unit Name and Acid Rain Program Identification Number]
[Unit Name and Acid Rain Program Identification Number]

Permit term

This permit shall be in effect from January 1, 1995 through December 31, 1999.

Permit Limits

(Note: A, B & C will need to be repeated for each unit, when applicable.)

A. Acid Rain Program Basic Limits

The Acid Rain Program Sulfur Dioxide Allowance Allocation and Nitrogen Oxides Emissions Limitation for the following unit at this source are as follows:

[Unit Name] [SO_2 Allocation (TPY) NO_x Limitation (unit)]

B. Federal Limits

The most stringent federally enforceable emissions limitations for Sulfur Dioxide and Nitrogen Oxides for the unit are as follows:

[SO_2 (unit)] [NO_x (TPY)]

C. Alternative Limitations

EPA has approved the following optional methods of compliance for this unit, subject to the terms and conditions that follow:

[Compliance Option]—(SFι ______ attached)

Terms and Conditions: In addition to the terms and conditions if SFι ______, the following terms and conditions shall apply: [other terms and conditions]

Under the approved alternative method(s) of compliance that are now activated, the permit limits shall be as follows:

Compliance year	SO_2 limitation	NO_x limitation
1995	[#] TPY	[#] (unit)
1996	[#] TPY	[#] (unit)
1997	[#] TPY	[#] (unit)
1998	[#] TPY	[#] (unit)
1999	[#] TPY	[#] (unit)

In the event that the Designated Representative activates a pre-approved alternative compliance plan during the permit term, the limits under that plan shall become the new enforceable limits and, when applicable, shall supersede the limits stated above.

Continuous Emissions Monitoring Requirements

A. The owners, operators and designated representative of the units at this source shall comply with all the emissions monitoring requirements of 40 CFR part 75, including:

1. The duty to collect and report emissions data for each unit at the source and to adopt quality assurance procedures and conduct quality assurance reviews of the emissions monitoring system and the data for sulfur dioxide, nitrogen oxides, opacity and volumetric flow at each unit at the source as specified in 40 CFR part 75; and

2. The duty to calculate emissions pursuant to the missing data provisions of 40 CFR part 75 if emissions monitoring data are not available for any affected unit during any period when such data are required;

B. The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other provisions of the operating permit for the source.

C. No affected unit or source shall use alternative monitoring system data or procedures unless the Administrator approves the alternative monitoring system in accordance with 40 CFR part 75, and the unit operates the system in accordance with that approval.

Recordkeeping and Reporting Requirements

A. The owners, operators, and designated representative of the affected units at the affected source shall keep the following records for a period of 5 years on site at the affected source governed by the permit or permit application:

1. The certificate of represntation for the designated representative for the source and each unit at the source, and all documents that support the certificate, as provided in 40 CFR part 72, subpart B.

2. All emissions monitoring information, including but not limited to calibration and maintenance records, quality assurance procedures information, and raw emissions and operation data used to generate emissions reports that a source or unit must collect under the requirements of 40 CFR part 75.

3. Copies of all reports required by 40 CFR parts 72–78; and

4. Copies of all documents, contracts, agreements, guarantees, schedules, operating procedures, allowance documentation, or any other records of information used to complete the permit application and compliance plan or to demonstrate compliance with the requirements of the Acid Rain program.

B. The designated representative shall submit quarterly and annual compliance certifications as required by 40 CFR part 72 subpart K and other provisions of 40 CFR parts 72–78.

C. For the currently activated alternative compliance plans, the following reporting requirements also shall apply:

[Compliance Plan Name]: [Reporting Requirement]

D. In the event that the Designated Represenative activates a pre-approved alternative compliance plan during the permit term, the reporting requirements under that plan shall be incorporated into this permit by reference and shall be binding on the source as long as the plan is in effect.

Duties

Each owner, operator, and designated representative of an affected unit shall have the following affirmative duties in connection with the Acid Rain program. Failure to fulfill or comply with these duties shall be a violation of the Act and of 40 CFR part 72. The duties are as follows:

A. To submit a permit application and proposed compliance plan under 40 CFR part 72 in accordance with the deadlines specified in § 72.30;

B. To submit in a timely manner any additional information that the permitting authority requires for the complete review of a permit application.

C. To operate any affected unit in compliance with the terms, conditions, requirements, and prohibitions of an Acid Rain permit application and proposed compliance plan properly submitted in accordance with title IV of the Act and of 40 CFR part 72 (including any amendments or modifications thereto required by the permitting authority), or of the superseding Acid Rain permit issued by the permitting authority.

D. To operate the unit in compliance with the monitoring requirements of 40 CFR part 75.

E. In the case of an affected unit with excess emissions in any calendar year, to pay

without demand the penalty required pursuant to 40 CFR part 77; and

F. In the case of an affected unit with excess emissions in any calendar year, to comply with the offset planning requirements of 40 CFR part 77 and an approved offset plan as required by 40 CFR part 77.

Prohibitions

Prohibitions. Any violation of the following prohibitions shall be a violation of the Act and 40 CFR part 72 by the owners, operators and designated representative of the affected unit and/or affected source:

A. No affected unit shall exceed the applicable emissions limitations of 40 CFR part 72–78, as follows:

1. No affected unit shall emit sulfur dioxide in any calendar year in excess of the allowances held in the unit's Allowance Tracking System compliance subaccount as of the allowance transfer deadline for use in the calendar year as provided in 40 CFR part 73. Each ton of sulfur dioxide emitted in excess of the allowances held shall constitute a separate violation of the Act.

2. No affected unit shall emit nitrogen oxides in excess of:

a. The annual emissions limitation for the unit by the type of boiler, as specified in 40 CFR part 76; or

b. The superseding limitation specified in an approved nitrogen oxides compliance option incorporated into the Acid Rain permit issued by the permitting authority in accordance with 40 CFR part 72, subpart D and 40 CFR part 75;

B. No person shall hold, use, or transfer any allowance except in accordance with Title IV of the Act and the regulations in 40 CFR parts 72–78.

C. No person shall use an allowance prior to the calendar year for which the allowance was allocated.

D. No person shall make a false statement in any submission required under 40 CFR parts 72–78, inclusive.

Liability

A. Any person who knowingly violates any requirement or prohibition of title IV of the Act, of 40 CFR part 72–78, of an Acid Rain permit application filed pursuant to the requirements of title IV of the Act and 40 CFR part 72–78, or of an Acid Rain permit, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.

B. All owners, operators, and designated representatives of any affected units governed by a multi-unit compliance plan that filed pursuant to the requirements of title IV of the Act and 40 CFR part 72–78 shall be jointly and severally liable for any violation of the plan at any unit governed by the compliance plan, including liability for failure to fulfill the obligations specified in 40 CFR part 77 and section 411 of the Act.

C. Any person who knowingly makes a false material statement in any record, submission, or report required by the Acid Rain program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.

D. No permit revision shall excuse past noncompliance.

Allowance Information

A. An allowance allocated by the Administrator under the Acid Rain program is a limited authorization to emit sulfur dioxide in accordance with the provisions of title IV of the Act and 40 CFR parts 70–78. Nothing in title IV, in 40 CFR parts 70–78, in this permit, or in any provision of law shall be construed to limit the authority of the United States to terminate or limit the authorization.

B. An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Effect on Other Provisions, Statutes and Agencies

A. Nothing in title IV, in 40 CFR parts 70–78, or in this permit relating to allowances shall be construed as limiting the number of allowances a unit can hold; provided, however, that the number of allowances held by a unit shall not affect the applicability of, or the affected source's obligation to comply with, any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards and State Implementation Plans.

B. Nothing in title IV, in 40 CFR parts 70–78, or in this permit shall be construed as requiring a change of any kind in any State law regulating electric utility rates and charges, or as affecting any State law regarding such State regulation, or as limiting such State regulation including any prudency review requirements under such a State law

C. Nothing in title IV, in 40 CFR parts 70–78, or in this permit shall be construed as modifying the Federal power Act, or as affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act.

D. Nothing in title IV, in 40 CFR parts 70–78, or in this permit shall be construed to interfere with or impair any program for competitive bidding for power supply in a State in which such program is established.

Definitions

This permit adopts by reference all definitions found in 40 CFR part 72.

Revisions

(Provisions describing the procedures and limitations applicable to permit revisions will be added consistent with 40 CFR subpart J.)

Phase II Acid Rain Permit Program

PROGRAM INFORMATION

- Introduction (to be added).
- Table of Contents.
- General Instructions (to be supplemented).
- Glossary (to be added).

FORMS AND INSTRUCTIONS

- Designated Representative Certificate Representation Forms 7220 and 7220A*.
- Acid Rain Phase II Permit Application Forms 72200 and 72200A.
- Repowering Extention Plan Forms 7244, 7244A and 7244B.
- NO_x Emissions Averaging Plan Form 7246**.
- Annual Compliance Certification Report Form 72402*.
- Excess Emissions Offset Planning Form 772 (Part 77)*.
- Excess Emissions Penalty Form 774 (Part 77)*.

BILLING CODE 6560-50-M

* These forms are included in Phase I Forms Package.

** This form will be included in the Part 76 Regulation.

PHASE II ACID RAIN PERMIT PROGRAM
INTRODUCTION, TABLE OF CONTENTS and GENERAL INSTRUCTIONS

I. INTRODUCTION: THE ACID RAIN PROGRAM

A. General Statutory Background on Acid Rain Regulation

[to be added]

B. Permit Program and Standard Forms

[to be added]

II. TABLE OF CONTENTS FOR INSTRUCTIONS PACKAGE

* These forms are included in the Phase I Forms Package.

** This form will be included in the Part 76 regulations.

III. GENERAL INSTRUCTIONS

A. Who Must Apply

[to be added]

B. When to File

- The Designated Representative Certification forms must be postmarked no later than midnight **January 1, 1996**. To expedite allowance trading and permit processing, we suggest you submit these forms as early as possible.

- Phase II permit applications including proposed compliance plans must be postmarked no later than midnight, **January 1, 1996**.

- If possible, Acid Rain compliance option forms should be submitted with the permit application. If a compliance plan is submitted after the permit application has been processed, a permit revision may be necessary. Because each compliance option has a specific deadline, a comprehensive list of the final date on which each form may be submitted is provided in Figure 1, below.

FIGURE 1: ACID RAIN COMPLIANCE OPTION FILING DEADLINES

Form Number	Compliance Option Form Name	Deadline
7244	Repowering Extension Proposal Plan	**January 1, 1996**
7244A	Repowering Technology Approval Request	**June 1, 1997**
7244B	Notification of Removal from Operation to Install Repowering Technology	No later than **60 days** prior to removal
7246	NO_x Emissions Averaging Plan	Any time during **Phase II**, as a permit revision
7247	NO_x Alternative Emissions Limitation Proposal	Any time during **Phase II**, as a permit revision
7247A	NO_x Alternative Emissions Limitation Proposal: Application for Final Limitation	No later than **90 days** before end of demonstration period

EPA Form xxxx

PHASE II ACID RAIN PERMIT PROGRAM
GENERAL INSTRUCTIONS (continued)

C. Where to File

If your state has an approved program under 40 CFR Part 70, send your Phase II Acid Rain permit forms to the address specified pursuant to such approval, with copies to the appropriate EPA Regional Office (Figure 2) and to EPA Headquarters, addressed to **Chief, Permits and Technologies Section**, Acid Rain Division (ANR-445), Office of Atmospheric and Indoor Air Programs, U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460.

If your State does not have an approved program under 40 CFR Part 70, send your Phase II Acid Rain permit forms to EPA headquarters (address given above), with copies to the appropriate EPA Regional Office (Figure 2) and to the appropriate State Air Pollution agency (list on page 3).

FIGURE 2: EPA REGIONAL OFFICES

Region #	States Included	Address
Region I	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont	Director, Air, Pesticides and Toxics Management Division U. S. Environmental Protection Agency John F. Kennedy Federal Building Boston, Massachusetts, 02203
Region II	New Jersey, New York, Puerto Rico, Virgin Islands	Director, Air and Waste Management Division U. S. Environmental Protection Agency Federal Office Building 26 Federal Plaza (Foley Square) New York, New York 10278
Region III	Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia	Director, Air and Waste Management Division U. S. Environmental Protection Agency Curtis Buildings Sixth and Walnut Streets Philadelphia, Pennsylvania 19106
Region IV	Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee	Director, Air and Waste Management Division U. S. Environmental Protection Agency 345 Courtland Street, N.E. Atlanta, Georgia 30365
Region V	Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin	Director, Air Management Division U. S. Environmental Protection Agency 230 South Dearborn Street Chicago, Illinois 60604
Region VI	Arkansas, Louisiana, New Mexico, Oklahoma, Texas	Director, Air Pesticides, and Toxics Division U. S. Environmental Protection Agency 1445 Ross Avenue Dallas, Texas 75202
Region VII	Iowa, Kansas, Missouri, Nebraska	Director, Air and Waste Management Division U. S. Environmental Protection Agency 726 Minnesota Avenue Kansas City, Missouri 66101
Region VIII	Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming	Director, Air and Waste Management Division U. S. Environmental Protection Agency 1860 Lincoln Street Denver, Colorado 80295
Region IX	Arizona, California, Guam, Hawaii, Nevada	Director, Air and Waste Management Division U. S. Environmental Protection Agency 215 Fremont Street San Francisco, California 94105
Region X	Alaska, Oregon, Idaho, Washington	Director, Air and Waste Management Division U. S. Environmental Protection Agency 1200 Sixth Avenue Seattle, Washington 98101

PHASE II ACID RAIN PERMIT PROGRAM
GENERAL INSTRUCTIONS (continued)

State Air Pollution Agencies

State of **Alabama**, Air Pollution Control Division, 645 S. McDonough Street, Montgomery, Alabama 36104.

State of **Arizona**, Department of Health Services, 1740 West Adams Street, Phoenix, Arizona 85007.

State of **Arkansas**, Division of Air Pollution Control, Department of Pollution Control and Ecology, 8001 National Drive, P.O. Box 9583, Little Rock, Arkansas 72209.

State of **California**, Air Resources Board, 1102 Q Street, Sacramento, California 95814.

State of **Colorado**, Department of Health, Air Pollution Control Division, 4210 East 11th Avenue, Denver, Colorado 80220.

State of **Connecticut**, Department of Environmental Protection, State Office Building, Hartford, Connecticut 06115.

State of **Delaware**, Delaware Department of Natural Resources and Environmental Control, 89 Kings Highway, P.O. Box 1401, Dover, Delaware 19901.

District of Columbia, Department of Consumer and Regulatory Affairs, 5000 Overlook Avenue S.W., Washington D.C. 20032.

State of **Florida**, Bureau of Air Quality Management, Department of Environmental Regulation, Twin Towers Office Building, 2600 Blair Stone Road, Tallahassee, Florida 32301.

State of **Georgia**, Environmental Protection Division, Department of Natural Resources, 205 Butler Street, S.E., East Tower, Atlanta, Georgia 30334.

State of **Idaho**, Department of Health and Welfare, Statehouse, Boise, Idaho 83701.

State of **Illinois**, Division of Air Pollution Control, 2200 Churchill Road, Springfield, Illinois 62706.

State of **Indiana**, Indiana Department of Environmental Management, 105 South Meridian Street, P.O. Box 6015, Indianapolis, Indiana 46206

State of **Iowa**, Iowa Department of Water, Air, and Waste Management, Henry A. Wallace Building, 900 East Grand, Des Moines, Iowa 50319.

State of **Kansas**, Kansas Department of Health and Environment, Bureau of Air Quality and Radiation Control, Forbes Field, Topeka, Kansas 66620.

State of **Kentucky**, Division of Air Pollution Control, Department for Natural Resources and Environmental Protection, U.S. 127, Frankfort, Kentucky 40601.

State of **Louisiana**, Program Administrator, Air Quality Division, Louisiana Department of Environmental Quality, P.O. Box 44096, Baton Rouge, Louisiana 70804.

State of **Maine**, Department of Environmental Protection, State House, Augusta, Maine 04330.

State of **Maryland**, Air Management Administration, Maryland Department of the Environment, 2500 Broening Highway, Baltimore, Maryland 21224.

Commonwealth of **Massachusetts**, Massachusetts Department of Environmental Quality Engineering, Division of Air Quality Control, One Winter Street, Boston, Massachusetts 02108.

State of **Michigan**, Air Pollution Control Division, Michigan Department of Natural Resources, Stevens T. Mason Building, 8th Floor, Lansing, Michigan 48926.

State of **Minnesota**, Minnesota Pollution Control Agency, Division of Air Quality, 520 Lafayette Road, St. Paul, Minnesota 55155.

State of **Mississippi**, Bureau of Pollution Control, Department of Natural Resources, P.O. Box 10385, Jackson, Mississippi 39209.

State of **Missouri**, Department of Natural Resources, P.O. Box 1368, Jefferson City, Missouri 65101.

State of **Montana**, Department of Health and Environmental Services, Cogswell Building, Helena, Montana 59601.

State of **Nebraska**, Department of Environmental Control, P.O. Box 94877, State House Station, Lincoln, Nebraska 68502.

State of **Nevada**, Department of Conservation and Natural Resources, Division of Environmental Protection, 201 South Fall Street, Carson City, Nevada 89710.

State of **New Hampshire**, New Hampshire Air Resources Agency, Health and Welfare Building, Hazen Drive, Concord, New Hampshire 03301.

State of **New Jersey**, Department of Environmental Protection, Division of Environmental Quality, Enforcement Element, John Fitch Plaza, CN-027, Trenton, New Jersey 08625.

State of **New Mexico**, Director, New Mexico Environmental Improvement Division, Health and Environmental Department, 1190 St. Francis Drive, Santa Fe, New Mexico 87503.

State of **New York**, Department of Environmental Conservation, Division of Air Resources, 50 Wolf Road, Albany, New York 12233.

State of **North Carolina**, Environmental Management Commission, Department of Natural and Economic Resources, Division of Environmental Management, Attention: Air Quality Section, P.O. Box 27687, Raleigh, North Carolina 27611.

State of **North Dakota**, State Department of Health and Consolidated Laboratories, Division of Environmental Engineering, State Capitol, Bismark, North Dakota 58501.

State of **Ohio**, Ohio Environmental Protection Agency, 1800 Watermark Drive, Box 1049, Columbus Ohio 43266-0149.

State of **Oklahoma**, Oklahoma State Department of Health, Air Quality Service, P.O. Box 53551, Oklahoma City, Oklahoma 73152.

State of **Oregon**, Department of Environmental Quality, Yeon Building, 522 S.W. Fifth, Portland, Oregon 97204.

Commonwealth of **Pennsylvania**, Department of Environmental Resources, 105 S. Second Street, P.O. BOX 2357, Harrisburg, Pennsylvania 17120.

State of **Rhode Island**, Department of Environmental Management, 204 Cannon Building, Davis Street, Providence, Rhode Island 02908.

State of **South Carolina**, Office of Environmental Quality Control, Department of Health and Environmental Control, 2600 Bull Street, Columbia, South Carolina 29201.

State of **Tennessee**, Department of Public Health, Division of Air Pollution Control, 256 Capitol Hill Building, Nashville, Tennessee 37219.

State of **Texas**, Air Pollution Control Board, 6330 Highway 290 East, Austin, Texas 78723.

State of **Utah**, Department of Health, Bureau of Air Quality, 288 North 1460 West, P.O. Box 16690, Salt Lake City, Utah 84116-0690.

State of **Vermont**, Vermont Agency of Environmental Conservation, Air Pollution Control, State Office Building, Montpelier, Vermont 05602.

Commonwealth of **Virginia**, Virginia State Air Pollution Board, Room 1106, Ninth Street Office Building, Richmond, Virginia 23219.

State of **Washington**, Department of Ecology, Olympia, Washington 98504.

State of **West Virginia**, Air Pollution Control Commission, 1558 Washington Street East, Charleston, West Virginia 25311.

State of **Wisconsin**, Department of Natural Resources, P.O. Box 7921, Madison, Wisconsin 53707.

EPA Form xxxx

PHASE II ACID RAIN PERMIT PROGRAM
GENERAL INSTRUCTIONS (continued)

D. Fees

[to be added]

E. Information Available to the Public

Information contained in these application forms upon request will be made available to the public for inspection and copying. However, you may request confidential treatment for certain information that you submit on certain supplementary forms. The specific instructions for each supplementary form state what information on the form, if any, may be claimed as confidential and what procedures govern the claim. No information on Forms ___ through ___ may be claimed as confidential.

F. Completion of Forms

(1) **Technical Form Completion Guidance:** Please type or print in the unshaded areas only. Some items have small graduation marks in the fill-in spaces. These marks indicate the number of characters that may be entered into our data system. The marks are spaced at 1/6" intervals and accommodate elite type (12 characters per inch). If you use another type you may ignore the marks, but the number of characters should not exceed the number of spaces provided.

If you print, place each character between the marks. Abbreviate if necessary to stay within the number of characters allowed for each item. Use one space for breaks between words, but not for punctuation marks unless they are needed to clarify your response.

"Mark" all appropriate check boxes with an "X" rather than a "✓."

(2) **Completeness Requirements:** Unless otherwise specified in instructions to the forms, each item in each form must be answered. To indicate that each item has been considered, enter "NA" for "not applicable" if a particular item does not fit the circumstances or characteristics of your facility or activity.

Even if you have previously submitted requested information to EPA or to an approved State agency, you must repeat the information in the space provided, unless the form and instructions indicate that a reference to prior submissions will suffice.

(3) **Paperwork Reduction Act Notification:** The time needed to complete and file the forms included in this package will vary depending on individual circumstances. The estimated times are listed in Figure 3, below.

Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing the burden, to **Chief, Information Policy Branch**, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, DC 20460; and to **Paperwork Reduction Project** (OMB 20xx-xxxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503.

FIGURE 3: PAPERWORK BURDEN ESTIMATES FOR ACID RAIN PERMIT FORMS

Form		Preparing the Form	Copying, Assembling and Sending the Form
Number(s)	Name		
7220 and 7220A	Designated Representative Certification		
72000 and 72000A	Acid Rain Phase II Permit Application		
7244	Repowering Extension Proposal Plan		
7244A	Repowering Technology Approval Request		
7244B	Notification of Removal from Operation to Install Repowering Technology		
7247	NO_x Alternative Emissions Limitation Proposal		
7247A	NO_x Alternative Emissions Limitation Proposal: Application for Final Limitation		
72402	Annual Compliance Certification Report		
772	Excess Emissions Offset Planning		
774 and 774A	Excess Emissions Penalty		

EPA Form xxxx

PHASE II ACID RAIN PERMIT PROGRAM
GLOSSARY OF ACID RAIN PROGRAM TERMS

GLOSSARY OF ACID RAIN PROGRAM TERMS

[to be added]

EPA Form xxxx

FORMS 72200 AND 72200A

Application for Phase II Acid Rain Permit

Form 72200

Application for Phase II Acid Rain Permit (Source Information)

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

Form 72200A

Application for Phase II Acid Rain Permit (Unit Information)

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

DRAFT 72200
Date 10/21/91
Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Application for Phase II Acid Rain Permit
(Source Information)

Follow Instructions for Form 72200.

I. SOURCE IDENTIFICATION

A. Source Name and Mailing Address

1. Source Name

2. Street or P.O. Box

3. City | 4. State | 5. Zip

B. Source Location

1. Street, Route Number or Other Specific Identifier

2. City | 3. State | 4. Zip

5. County Name | 6. Phone (area code & number)

C. Other Source Information

1. Operating Company

2. NERC Region | 3. Aggregate Baseline (mmBtu)

II. UNIT IDENTIFICATION

A. Appendix B Units

If more than 4 units, copy this sheet and enter number of copies here →

1. Unit Name
1
2. Short Name | 3. Unit ARP ID Number

1. Unit Name
2
2. Short Name | 3. Unit ARP ID Number

1. Unit Name
3
2. Short Name | 3. Unit ARP ID Number

1. Unit Name
4
2. Short Name | 3. Unit ARP ID Number

Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

B. Non-Appendix B Units If more than 4 units, copy this sheet and enter number of copies here

1	1. Unit Name	
	2. Short Name	3. Unit ARP ID Number
2	1. Unit Name	
	2. Short Name	3. Unit ARP ID Number
3	1. Unit Name	
	2. Short Name	3. Unit ARP ID Number
4	1. Unit Name	
	2. Short Name	3. Unit ARP ID Number

III. CERTIFICATE OF REPRESENTATION

☐ Certificate of Representation for this source and each unit at this source is included (either original or copy).

IV. STANDARD PROVISIONS & PROHIBITIONS

A. Duties, Prohibitions and Liability

1. **Duties.** Each owner, operator, and designated representative of an affected unit shall have the following affirmative duties in connection with the Acid Rain program. Failure to fulfill or comply with these duties shall be a violation of the Act and of 40 CFR Part 72. The duties are as follows:
   a. To submit a permit application and proposed compliance plan under 40 CFR Part 72 in accordance with the deadlines specified in §72.30;
   b. To submit in a timely manner any additional information that the permitting authority requires for the complete review of a permit application;
   c. To operate any affected unit in compliance with the terms, conditions, requirements, and prohibitions of an Acid Rain permit application and proposed compliance plan properly submitted in accordance with Title IV of the Act and of 40 CFR Part 72 (including any amendments or modifications thereto required by the permitting authority), or of the superseding Acid Rain permit issued by the permitting authority;
   d. To operate the unit in compliance with the monitoring requirements of 40 CFR Part 75;
   e. In the case of an affected unit with excess emissions in any calendar year, to pay without demand the penalty required pursuant to 40 CFR Part 77; and,
   f. In the case of an affected unit with excess emissions in any calendar year, to comply with the offset planning requirements of 40 CFR Part 77 and an approved offset plan as required by 40 CFR Part 77.

2. **Prohibitions.** Any violation of the following prohibitions shall be a violation of the Act and 40 CFR Part 72 by the owners, operators and designated representative of the affected unit and/or affected source:
   a. No affected unit shall exceed the applicable emissions limitations of 40 CFR Parts 72-78, as follows:
      i. No affected unit shall emit sulfur dioxide in any calendar year in excess of the allowances held in the unit's Allowance Tracking System compliance subaccount as of the allowance transfer deadline for use in the calendar year as provided in 40 CFR Part 73. Each ton of sulfur dioxide emitted in excess of the allowances held shall constitute a separate violation of the Act.
      ii. No affected unit shall emit nitrogen oxides in excess of:
         A. the annual emissions limitation for the unit by the type of boiler, as specified in 40 CFR Part 76; or,
         B. the superseding limitation specified in an approved nitrogen oxides compliance option incorporated into the Acid Rain permit issued by the permitting authority in accordance with 40 CFR Part 72, Subpart D and 40 CFR Part 75;
   b. No person shall hold, use, or transfer any allowance except in accordance with Title IV of the Act and the regulations in 40 CFR Parts 72-78;
   c. No person shall use an allowance prior to the calendar year for which the allowance was allocated; and,
   d. No person shall make a false statement in any submission required under 40 CFR Parts 72-78, inclusive.

NOTE: Section IV. STANDARD PROVISIONS & PROHIBITIONS is continued on Page 3 of this form →

Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

IV. STANDARD PROVISIONS & PROHIBITIONS (cont.)

3. Liability

a. Any person who knowingly violates any requirement or prohibition of Title IV of the Act, of 40 CFR Parts 72-78, of an Acid Rain permit application filed pursuant to the requirements of Title IV of the Act and 40 CFR Parts 72-78, or of an Acid Rain permit, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to Section 113(c) of the Act.

b. All owners, operators, and designated representatives of any affected units governed by a multi-unit compliance plan that is filed pursuant to the requirements of Title IV of the Act and 40 CFR Parts 72-78 shall be liable for any violation of the plan at any unit governed by the compliance plan, including liability for failure to fulfill the obligations specified in 40 CFR Part 77 and Section 411 of the Act.

c. Any person who knowingly makes a false material statement in any record, submission, or report required by the Acid Rain program shall be subject to criminal enforcement pursuant to Section 113(c) of the Act and 18 U.S.C. 1001.

d. No permit revision shall excuse past noncompliance.

B. Standard Provisions

1. Continuous Emissions Monitoring Requirements

a. The owners, operators and designated representative of the units at this source shall comply with all the emissions monitoring requirements of 40 CFR Part 75, including:

i. The duty to collect and report emissions data for each unit at the source, to adopt quality assurance procedures, and to conduct quality assurance reviews of the emissions monitoring system and the data for sulfur dioxide, nitrogen oxides, opacity and volumetric flow at each unit at the source as specified in 40 CFR Part 75; and,

ii. The duty to calculate emissions pursuant to the missing data provisions of 40 CFR Part 75 if emissions monitoring data are not available for any affected unit during any period when such data are required.

b. The requirements of 40 CFR Part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other provisions of the operating permit for the source.

c. No affected unit or source shall use alternative monitoring system data or procedures unless the Administrator approves the alternative monitoring system in accordance with 40 CFR Part 75, and the unit operates the system in accordance with that approval.

2. Recordkeeping and Reporting Requirements

a. The owners, operators, and designated representative of the affected units at the affected source shall keep the following records for a period of 5 years on site at the affected source governed by the permit or permit application.

i. The certificate of representation for the designated representative for the source and each unit at the source, and all documents that support the certificate, as provided in 40 CFR Part 72, Subpart B;

ii. All emissions monitoring information, including but not limited to calibration and maintenance records, quality assurance procedures information, and raw emissions and operation data used to generate emissions reports that a source or unit must collect under the requirements of 40 CFR Part 75;

iii. Copies of all reports required by 40 CFR Parts 72-78; and,

iv. Copies of all documents, contracts, agreements, guarantees, schedules, operating procedures, allowance documentation, or any other records of information used to complete the permit application and compliance plan or to demonstrate compliance with the requirements of the Acid Rain program.

b. The designated representative shall submit quarterly and annual compliance certifications as required by 40 CFR Part 72 Subpart K and other provisions of 40 CFR Parts 72-78.

3. Allowance Information

a. An allowance allocated by the Administrator under the Acid Rain program is a limited authorization to emit sulfur dioxide in accordance with the provisions of Title IV of the Act and 40 CFR Parts 72-78. Nothing in Title IV, in 40 CFR Parts 72-78, in this permit application or in any provision of law shall be construed to limit the authority of the United States to terminate or limit the authorization.

b. An allowance allocated by the Administrator under the Acid Rain program does not constitute a property right.

4. Effect on Other Authorities

a. Nothing in Title IV, in 40 CFR Parts 70-78, or in this application shall be construed as limiting the number of allowances a unit can hold; *provided*, that the number of allowances held by a unit shall not affect the applicability of, or the affected source's obligation to comply with, any other provision of the Act, including the provisions of Title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans.

b. Nothing in Title IV, in 40 CFR Parts 70-78, or in this application shall be construed as requiring a change of any kind in any State law regulating electric utility rates and charges, or as affecting any State law regarding such State regulation, or as limiting such State regulation, including any prudence review requirements under such a State law.

c. Nothing in Title IV, in 40 CFR Parts 70-78, or in this application shall be construed as modifying the Federal Power Act or as affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act.

d. Nothing in Title IV, in 40 CFR Parts 70-78, or in this application shall be construed to interfere with or impair any program for competitive bidding for power supply in a State in which such program is established.

5. Definitions. This application adopts by reference all definitions found at 40 CFR Part 72.

V. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative

B. Signature	C. Date Signed

Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

FOR EPA USE ONLY

1. Date Received: ______________
2. Date of Initial Review: ______________ By: ______________
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: ______________
3. Date of Final Approval: ______________ By: ______________
4. Date Notice Sent: ______________ By: ______________

Comments:

DRAFT 72200A
Date 10/21/91
Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Application for Phase II Acid Rain Permit
(Unit Information)

Follow Instructions for Form 72200A.

I. UNIT IDENTIFICATION

A. Unit ARP ID Number	B. Short Name

C. This unit is *(mark all that are applicable)*:

- [ ] 1. Existing
- [ ] 2. Opt-in
- [ ] 3. New
- [ ] 4. Coal-fired *(complete I.D., below)*
- [ ] 5. Part of a common stack *(attach Form #XXXX)*
- [ ] 6. Multi-header

D. The boiler type(s) at this unit is(are):

	Emissions Limits
[ ] 1. Tangentially fired	TBA
[ ] 2. Dry bottom wall-fired	TBA
[ ] 3. Not applying cell burner technology	TBA
[ ] 4. Wet bottom wall-fired	TBA
[ ] 5. Cyclone	TBA
[ ] 6. Applying cell burner technology	TBA
[ ] 7. Other *(describe)*: a.	
b.	
c.	

II. EMISSIONS LIMITATIONS

A. Sulfur Dioxide

- [ ] 1. This unit proposes to receive the following Phase II Allowance Allocation during the permit term *(TPY)*: →
- [ ] 2. If approved, a repowering plan will govern the emissions limits.
- [ ] 3. This new unit will be subject to the emissions limits listed in Part III, below.
- [ ] 4. This opt-in unit will be subject to the emissions limits established in 40 CFR Part XX *(attach Form #XXXX)*.

B. Nitrogen Oxides

- [ ] 1. This unit proposes to meet the emissions limit(s) based on the boiler type(s) identified above.
- [ ] 2. This unit proposes an alternative emissions limit *(see Part IV, below, and attached compliance plan forms)*.
- [ ] 3. Nitrogen Oxides emissions limitations information is not available at this time. Complete Nitrogen Oxides compliance information will be submitted no later than January 1, 1998 on an amended copy of this form.

III. NEW UNIT EMISSIONS LIMITATIONS

- [ ] A. This new unit is specified in Part 73 as eligible for a Phase II Allocation. The allocation for this unit is *(TPY)*:
- [ ] B. This new unit is not specified in Part 73 and has the following characteristics:
  1. Annual fuel consumption *(mmBtu)*: →
  2. Allowable Sulfur Dioxide emissions rate *(lbs/mmBtu)*: →

C. This new unit commenced/will commence operation on *(mm/dd/yy)*: →

72200A/Pg. 1

Please type or print in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval expires X-XX-XX

IV. COMPLIANCE PLAN INFORMATION

A. Sulfur Dioxide Compliance Plan

This unit will hold allowances to emit not less than its total annual emissions and:

☐ 1. Will meet the Phase II deadline (1/1/2000).

☐ 2. Seeks approval for a repowering extension that:

☐ a. Has been certified (copy included).

☐ b. Has not yet been certified.

B. Nitrogen Oxides Compliance Plan

This unit:

☐ 1. Will meet the Title IV emissions limit.

☐ 2. Seeks approval for the following compliance option(s):

☐ a. Emissions averaging *(attach Form #XXXX).*

☐ b. Alternative emissions limits *(attach Form #XXXX).*

V. MONITORING PLAN

☐ A. This unit has an approved monitoring plan.

☐ B. This unit has attached a monitoring plan for approval.

☐ C. Each monitor at this unit has been certified.

☐ D. Initial monitor verification test results are attached for certification.

☐ E. Initial monitor verification test results were submitted for certification on *(mm/dd/yy)*: ______

☐ F. Initial monitor verification test results will be submitted in accordance with Part 75.

VI. STANDARD PROVISIONS AND PROHIBITIONS

The standard provisions and prohibitions from Part IV of the **Application for a Phase II Acid Rain Permit (Source Information)** are incorporated by reference and shall apply with full force and effect to this unit.

VII. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*	B. DR ID Number

C. Signature	D. Date Signed

FOR EPA USE ONLY

1. Date Received: ______
2. Date of Initial Review: ______ By: ______
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: ______
3. Date of Final Approval: ______ By: ______
4. Date Notice Sent: ______ By: ______

Comments:

Phase II Acid Rain Permit Program—Instructions for Form #72200 and 72200A

Forms #72200 and 72200A Application for Phase II Acid Rain Permit

[**Note:** We anticipate that, in light of experience with Phase I permitting and the needs of State Programs, the forms and these instructions will be revised substantially prior to the time of actual implementation of Phase II.]

Introduction

Clean Air Act section 408 and the regulations implementing that section at 40 CFR part 72 establish a permit program for affected sources under the Acid Rain Program. Subpart C of those regulations, 40 CFR 72.30 *et seq.* sets forth the requirements for and contents of Acid Rain permit applications and compliance plans.

In Phase II the Designated Representative for each Phase II affected source must submit a permit application and compliance plan for that source. These will include sources with units listed on appendix B, new units and opt-in units. When a given source consists of more than one unit, the Designated Representative must file a compliance plan for the source (or "facility") that covers all such units. However, for each unit, the Designated Representative must demonstrate individual compliance with the applicable Acid Rain Program limits.

The permit application forms are designed to accommodate both of these requirements. For each source that the Designated Representative represents, he or she will submit source-identifying information on SF# 72200. The Designated Representative also must submit a unit application on SF# 72200A that will state the limits for the unit and will indicate how the unit will comply with those limits. For a unit that plans an Acid Rain compliance option, (*e.g.*, repowering, NO_x emissions averaging) the Designated Representative also will be required to complete the form or forms designed to allow the applicant to demonstrate compliance through any such compliance option. Instructions for those compliance options forms accompany the individual forms. The source information form, the application forms for the units at the source and attached compliance options forms constitute the "Source Compliance Plan."

The statute and regulations provide that the permit application and compliance plan shall be binding on the owner, operator and Designated Representative of the unit and shall be enforceable in lieu of a permit until the permitting authority issues a permit to the source. Permit applications are due for all Phase II affected sources (except new units; see Section II of the general instructions for "Who Must Apply") on January 1, 1996.

Instructions for Form 72200—Application for Phase II Acid Rain Permit (Source Information)

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. Source Information

A. Name: Provide the name of the source or facility for which this application is filed. This name will include the company name and a name for the source, *e.g.*, "ABC Utility Electric Power Station."

B. Location: 1–4. Provide a descriptive address for the source; if there is no street address or route number, give the most accurate alternative geographic information (e.g., "Intersection of Rts. 6 and 502" or the section number from county records). If the location is the same as the address given in I A. above, enter "Same as above" on line 1, and skip to 5, below.

5. List the county in which the source is located.

6. Provide the main phone number for the source.

II. Unit Identification

List the affected units. Provide information for Appendix B units in Section A. In Section B, list only those non-Appendix B units that you will be proposing as part of an alternative compliance plan. (You will need to complete a SF# 72200A for each of the units you list.) For each unit provide the following:

1. Fill in the name of the affected unit (e.g., "ABC Elect. Gen. Unit #4.")

2. Give a short name that is commonly used or could be used as an easy identification of the unit (e.g., "ABC #4.")

3. Provide the Acid Rain Program Identification Number for the unit. This is the source number, which appears at the top center of the first page of this form, plus three digits that identify the unit (e.g. "004"). Enter the three digits in the space provided. (Acid Rain Program Identification Numbers are listed in Appendix B.)

III. Certificate of Representation

Mark this box to indicate you are submitting the original or a copy of the Certificate of Representation for this source.

IV. Standard Provisions and Prohibitions

These provisions and prohibitions apply to all Acid Rain permit applications and proposed compliance plans, which are binding until the permitting authority either makes an initial permitting decision or disapproves the application. These provisions attach to the source and to all affected units that are a part of that source.

V. Certification

The proposed designated representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See part III, section A of the Forms Instructions Package for more information about the legal effect of certification.

Instructions for Form 72200A—Application for Phase II Acid Rain Permit (Unit Information)

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. Unit Identification

A. Enter the unit Acid Rain Identification Number.

B. Enter the short name that is commonly used or could be used for easy identification of the unit (e.g., "ABC #4").

C. Mark all applicable boxes that identify the unit:

1. An Existing Unit is a unit that commenced commercial operation before November 15, 1990, including any unit that is modified, reconstructed or repowered after November 15, 1990. Existing unit does not include a simple combustion turbine or a unit that serves a generator with a nameplate capacity of 25 MWe or less.

2. An Opt-in Unit is a unit defined in 40 CFR part 74 as (to be added).

3. A New Unit is any unit that commenced commercial operation on or after November 15, 1990, including any unit that serves a generator with a nameplate capacity of 25 MWe or less, or is a simple combustion turbine, or did not serve a generator with a nameplate capacity of greater than 25 MWe before November 15, 1990 and serves a generator with a nameplate capacity of greater than 25 MWe on or after November 15, 1990.

4. Mark whether the unit is coal-fired. All coal-fired units become affected units for purposes of Nitrogen Oxides in Phase II. Complete Part I D, below.

5. Indicate whether the unit shares a common stack. All units that share a common stack must complete a common stack plan on SF#____.

6. Indicate whether the unit is multi-header.

D. Identify the boiler type(s) at the unit by marking appropriate checkboxes.

II. Emissions Limitations

A. Sulfur Dioxide Emissions Limitations: Choose the appropriate checkbox.

1. For a unit that is listed in appendix B at 40 CFR part 73, enter the allowance allocation from the Appendix. Mark the check box if the unit proposes to receive this allocation.

2. Mark here if the appendix B unit will seek approval for a repowering plan that will govern the emissions limits.

3. Mark here if the unit is a new unit and complete section III, below.

4. Mark here for an opt-in unit. Emissions limit for opt-in units will be established pursuant to 40 CFR part ____. (Attach SF#XXXX)

B. Nitrogen Oxides: Mark either 1, 2 or 3.

1. Mark this box if this unit proposes to meet the emissions limits listed in Part I D, above.

2. Mark here if the unit proposes a different limit or a different schedule for meeting the limit under a Nitrogen Oxide compliance option.

3. Mark here if NO_x emissions limitations information is not available at this time. You must submit complete NO_x compliance information no later than January 1,1998 on an amended copy of this form.

III. New Unit Emissions Limitations

A. If the new unit is specified in Part 73 for a Phase II allocation, enter the allocation here.

B. If the new unit is not specified in Part 73, enter the following:

1. Annual fuel consumption on a Btu basis at a 65% capacity factor.

2. The allowable SO_2 emissions rate (the SIP limit or other controlling limit) in lbs/Btu. and check the box to indicate that you have

attached a commerce operation schedule. This schedule must include dates for:

- Completion of construction
- Commerce operation
- Start-up testing
- Commerce commercial operation

IV. Compliance Plan Information

Under 408(b) of the CAAA, all Acid Rain permit applicants are required to submit a compliance plan that indicates how the unit will meet the emissions reduction requirements of Title IV. Section 408(b) of the Clean Air Act provides that a unit can meet compliance planning requirements by submitting a statement that the unit will meet the applicable emissions limitations in a timely manner. For any unit that proposes to meet the emissions limitations requirements by means of an alternative method of compliance, the proposed compliance plan must include a description of the schedule and means by which the unit will rely on one or more of the methods in the manner and time authorized under the statute.

A. SO_2 Compliance Plan: All units must hold sufficient allowances.

1. Mark here if the unit will achieve compliance through allowances by the Phase II deadline (1/1/2000).

2. Mark here if the unit seeks an extension on the deadline for meeting the SO_2 limits through a repowering plan, and further indicate

a. If the repowering technology has been certified (attach copy), or

b. If the repowering technology has not yet been certified.

B. NO_x Compliance Plan: All coal-fired units are regulated in Phase II and are required to meet title IV NO_x emissions limits by 2000. A unit can apply for alternative limits or can apply for an extension of the limits under NO_x compliance options.

a. Mark this box if you plan to meet the regulatory emissions limit that applies to the boiler or boilers at your unit, as listed in Part II, Section B of this unit application.

b. Mark this box if the unit seeks approval for one or more of the compliance options. Indicate the options for which approval is sought by marking the appropriate box(es):

i. Emissions Averaging: Clean Air Act section 407(e) and the regulations implementing that part at 40 CFR 72.46, allows the Designated Representative of two or more units subject to the Title IV emissions limit to submit a proposal to set alternative contemporaneous annual emissions limits for the units. These new limits must assure that the resulting emissions will be no greater than they would have been had the statutory limits been applied at each unit. A more complete description of this provision and of the components of the plan will be included in 40 CFR part 76.

ii. Alternative Emissions Limit: Clean Air Act section 407(d) and the regulations implementing that section at 40 CFR 72.47 allow the Administrator to authorize an alternative NO_x emissions limit for a unit that can adequately demonstrate its inability to meet the limit using NO_x low burner technology. A more complete description of this provision and of the components of the plan will be included in 40 CFR part 76.

V. Monitoring Plan

Clean Air Act section 412 requires that all units that are subject to Title IV permitting requirements monitor sulfur dioxide, nitrogen oxides, opacity and volumetric flow using Continuous Emission Monitors (CEMS) or an alternative monitoring system that is demonstrated to provide data to that provided by a CEMS. The unit also must submit a monitoring plan on SF# [7510].

Indicate the status of the monitoring plan by checking the appropriate box.

VI. Standard Provisions and Prohibitions

The standard provisions and prohibitions listed in the source application form are incorporated by reference into this unit application and apply with full force and effect to this unit.

VII. Certification

The proposed designated representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See part III, section A of the Forms Instructions Package for more information about the legal effect of certification.

BILLING CODE 6560-50-M

FORMS 7244, 7244A and 7244B

Repowering Extension Plan

Form 7244

Repowering Extension Plan Proposal

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

Form 7244A

Repowering Technology Approval Request

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

Form 7244B

Notification of Removal from Operation to Install Repowering Technology

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

DRAFT 7244
Date 10/21/91

Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Repowering Extension Plan Proposal
(Single Unit Plan)

Follow Instructions for Form 7244.

I. UNIT IDENTIFICATION

A. Unit ARP ID Number

B. Short Name

	SIP Limit	1995 Actual
C. Sulfur Dioxide Emissions Rate		

D. The above identified unit will be:

☐ 1. Repowered

☐ 2. Replaced with a repowered unit *(complete I.E. below)*

E. If the unit identified above will be replaced with a repowered unit, identify the repowered unit:

1. Unit ARP ID Number

2. Short Name

II. REPOWERING PROPOSAL

A. Identify the repowering technology that will be used at the repowered unit:

☐ 1. Atmospheric fluidized bed combustion

☐ 2. Pressurized fluidized bed combustion

☐ 3. Integrated gasification combined cycle

☐ 4. Magnetohydrodynamics

☐ 5. Integrated gasification fuel cells

☐ 6. Direct coal-fired turbine

☐ 7. Indirect coal-fired turbine

☐ 8. Other qualified repowering technology *(complete II.B., below)*

B. For all technologies, indicate status of technology certification:

☐ 1. This repowering technology has been certified *(documentation is included).*

☐ 2. Certification for this repowering technology is pending.

III. ACTIVATION OF PLAN

Mark the appropriate box:

☐ A. This plan will go into effect upon approval.

☐ B. This plan is contingent. The applicant will notify the Administrator no later than **December 31, 1997** of a decision to activate the plan.

IV. REPOWERING COMPLIANCE SCHEDULE

A. Complete design engineering *(mm/dd/yy)* →	
B. Remove unit from operation to install qualified repowering technology *(mm/dd/yy)* →	
C. Start construction *(mm/dd/yy)* →	
D. Complete construction *(mm/dd/yy)* →	
E. Start-up testing *(mm/dd/yy)* →	
F. Commence commercial operation *(mm/dd/yy)* →	
G. (For replaced units) Permanent shut-down date for existing unit *(mm/dd/yy)* →	

Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

V. STANDARD PROVISIONS & PROHIBITIONS

A. Emissions Limitations

1. Extension Period (January 1, 2000, until removal of unit from operation to install repowering technology)
   a. The annual Sulfur Dioxide emissions prior to the date of removal of the unit from operation to install the repowering technology or of permanent shutdown for replacement shall not exceed the allowances held in the unit's Allowance Tracking System (ATS) compliance subaccount by the allowance transfer deadline.
   b. Any unit with an approved repowering extension shall not be required to comply with the applicable Nitrogen Oxides limitation for that unit during the extension period.
2. Following Removal for Installation
   a. The annual Sulfur Dioxide emissions beginning on the date of removal of the unit from operation to install the repowering technology or of permanent shutdown for replacement shall not exceed the allowances held in the unit's Allowance Tracking System (ATS) compliance subaccount by the allowance transfer deadline.
   b. Any unit with an approved repowering extension shall not emit Nitrogen Oxides in excess of the applicable limitation in the attached permit application for that unit beginning on the date that the unit will be shut down for repowering or permanently shut down for replacement.
3. In no event shall any unit governed by a repowering extension plan be excused from compliance with any other requirement of the Act, including any National Ambient Air Quality Standard requirement, any State Implementation Plan requirement, or any New Source Performance Standard.

B. Test Methods

Test methods shall be those indicated in the attached permit application.

C. Reporting/Compliance Certification Requirements

1. Not later than January 1, 2000, the Designated Representative shall submit to the Administrator and the permitting authority:
   a. Satisfactory documentation of a preliminary design engineering effort.
   b. A copy of an executed and binding contract for the majority of the equipment to repower such unit.
   c. Any additional information specified by the Administrator.
2. The Designated Representative shall provide written notice by submittal of standard form #7244B to the permitting authority sixty (60) days in advance of the date of the removal of the affected unit from operation to replace the unit or to install repowering technology and in no event any later than 12/31/2003.
3. Not later than 60 days after the repowered unit commences operation at full load, the Designated Representative shall submit a report comparing actual hourly emissions of any pollutant regulated under the Act at the repowered unit and at the existing unit prior to repowering.
4. The Designated Representative shall provide written notice to the permitting authority within ten (10) days of any deviations from this repowering plan.
5. The Designated Representative shall provide written notice sixty (60) days prior to any proposed revision in a scheduled increment of progress.
6. Should the technology, demonstration or information requirements of 40 CFR Section 72.44 not be met, the approved repowering extension shall be deemed null and void.

D. Prohibitions

1. It shall be a violation of the Act to transfer any allowances allocated to a unit granted a repowering extension during the extension period.
2. The Designated Representative shall not replace an existing unit with a repowered unit unless the following conditions are met:
   a. the replacement unit shall have the same Designated Representative as the replaced unit;
   b. the replacement unit shall replace the existing unit; and,
   c. the existing unit shall be retired from service on or before the date the replacement unit commences commercial operation.
3. Beginning in the year 2000 it shall be a violation of the Act for the Designated Representative, owner, or operator of a repowered unit to fail to comply with the requirements of this section, or of any other regulations or permit requirements implementing this section.
4. Should the technology, demonstration, or information requirements of this section not be met, the approved repowering extension shall be deemed null and void.
5. No repowering extension plan shall be terminated after December 31, 1999. The Designated Representative for a repowering unit, however, may withdraw and terminate the repowering extension plan at any time prior to December 31, 1999 using the administrative permit amendment procedures set forth at 40 CFR §72.303.
6. Any unit that is granted an extension under this section shall not be eligible for a waiver under Section 111(j) of the Act.
7. No new unit that is designated as a replacement unit for an existing unit qualifying for an extension under this section and that is located at a different site than the existing unit shall receive an exemption from the requirements imposed under Title I of the Act, including Section 111 of the Act.

VI. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*	
B. Signature	C. Date Signed

Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FOR EPA USE ONLY

1. Date Received: ____________
2. Date of Initial Review: ____________ By: ____________
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: ____________
3. Date of Final Approval: ____________ By: ____________
4. Date Notice Sent: ____________ By: ____________

Comments:

DRAFT 7244A
Date 10/21/91
Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Repowering Technology Approval Request
(Single Unit Report)

Follow Instructions for Form 7244A.

I. UNIT IDENTIFICATION

A. Unit ARP ID Number

B. Short Name

C. This unit will be:
☐ 1. Repowered
☐ 2. Replaced with a repowered unit

D. If the unit identified above will be replaced with a repowered unit, identify the repowered unit:

1. Unit ARP ID Number

2. Short Name

II. TECHNOLOGY IDENTIFICATION

A. Identify the repowering technology that will be used at the repowered unit:

☐ 1. Atmospheric fluidized bed combustion
☐ 2. Pressurized fluidized bed combustion
☐ 3. Integrated gasification combined cycle
☐ 4. Magnetohydrodynamics
☐ 5. Integrated gasification fuel cells
☐ 6. Direct coal-fired turbine
☐ 7. Indirect coal-fired turbine
☐ 8. Qualified derivative of ______ [one of the above listed methods] *(see II.C., below)*
☐ 9. Other qualified repowering technology *(see II.C, below)*

☐ B. Attached is a vendor guarantee that estimates the performance characteristics of the repowering technology consistent with the requirements of 40 CFR Section 72.44(c).

☐ C. Attached is a vendor guarantee demonstrating that the non-listed technology can meet the performance characteristics specified in 40 CFR Section 72.2.

III. STANDARD PROVISIONS & PROHIBITIONS

Prohibition
No repowering extension shall be fully approved until the Administrator approves the repowering technology listed on this form, pursuant to 40 CFR Section 72.44.

IV. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*

B. Signature

C. Date Signed

FOR EPA USE ONLY

1. Date Received: ______
2. Date of Initial Review: ______ By: ______
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: ______
3. Date of Final Approval: ______ By: ______
4. Date Notice Sent: ______ By: ______

Comments:

DRAFT 7244B
Date 10/21/91
Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Notification of Removal from Operation to Install Repowering Technology (Single Unit Report)

Follow Instructions for Form 7244B.

I. UNIT IDENTIFICATION

A. Unit ARP ID Number

B. Short Name

II. NOTIFICATION

☐ A. The unit identified above will be removed from operation for installation of repowering technology on *(mm/dd/yy)*:

☐ B. The unit identified above will be removed from operation permanently on *(mm/dd/yy)*:

III. STANDARD PROVISIONS & PROHIBITIONS

A. Emissions Limitations

1. The annual Sulfur Dioxide emissions beginning on the date of removal of the unit from operation to install the repowering technology or of permanent shutdown for replacement shall not exceed the allowances held in the unit's Allowance Tracking System (ATS) compliance sub-account by the allowance transfer deadline.
2. Any unit with an approved repowering extension shall not emit Nitrogen Oxides in excess of the applicable limitation in the attached permit application for that unit beginning on the date that the unit will be shut down for repowering or permanently shut down for replacement.
3. In no event shall any unit governed by a repowering extension plan be excused from compliance with any other requirement of the Act, including any NAAQS requirement, any SIP requirement, or any NSPS.

B. Test Methods

Test methods shall be those indicated in the attached permit application.

C. Reporting/Compliance Certification Requirements

1. Not later than 60 days after the repowered unit commences operation at full load, the Designated Representative shall submit a report comparing actual hourly emissions of any pollutant regulated under the Act at the repowered unit and at the existing unit prior to repowering.
2. The Designated Representative shall provide written notice to the permitting authority within 10 days of any deviations from this repowering plan.
3. The Designated Representative shall provide written notice 60 days prior to any proposed revision in a scheduled increment of progress.
4. Should the technology, demonstration or information requirements of 40 CFR Section 72.44 not be met, the approved repowering extension shall be deemed null and void.

D. Prohibitions

1. It shall be a violation of the Act to transfer any allowances allocated to a unit granted a repowering extension during the extension period.
2. The Designated Representative shall not replace an existing unit with a repowered unit unless the following conditions are met:
   a. the replacement unit shall have the same Designated Representative as the replaced unit;
   b. the replacement unit shall replace the existing unit; and,
   c. the existing unit shall be retired from service on or before the date the replacement unit commences commercial operation.
3. Beginning in the year 2000 it shall be a violation of the Act for the Designated Representative, owner, or operator of a repowered unit to fail to comply with the requirements of this section, or of any other regulations or permit requirements implementing this section.
4. Should the technology, demonstration, or information requirements of this section not be met, the approved repowering extension shall be deemed null and void.
5. No repowering extension plan shall be terminated after December 31, 1999. The Designated Representative for a repowering unit, however, may withdraw and terminate the repowering extension plan at any time prior to December 31, 1999, using the administrative permit amendment procedures set forth at 40 CFR §72.303.
6. Any unit that is granted an extension under this section shall not be eligible for a waiver under Section 111(j) of the Act.
7. No new unit that is designated as a replacement unit for an existing unit qualifying for an extension under this section and that is located at a different site than the existing unit shall receive an exemption from the requirements imposed under Title I of the Act, including Section 111 of the Act.

IV. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*

B. Signature

C. Date Signed

7244B/pg.1

Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FOR EPA USE ONLY

1. Date Received: ____________
2. Date of Initial Review: ____________ By: ____________
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: ____________
3. Date of Final Approval: ____________ By: ____________
4. Date Notice Sent: ____________ By: ____________

Comments:

BILLING CODE 6560-50-C

7244B/pg.2

Phase II Acid Rain Permit Program Instructions for Form #7244, 7244A and 7244B

Forms #7244, 7244A and 7244B Repowering Extension Plan Forms

Clean Air Act Section 409 and the regulations implementing that section at 40 CFR 72.44 provide that an existing unit may be granted an extension of its Phase II Acid Rain emissions limitations from January 1, 2000 to December 31, 2003. Units that are eligible to apply for a repowering extension are existing coal-fired or oil fired utility units that had an actual 1985 sulfur dioxide emissions rate equal or greater than 1.2 lbs/mmBtu. To qualify for such an extension, the Designated Representative for the unit must demonstrate that the unit will be repowered with qualifying clean coal technology, or will be replaced by a new unit that uses such repowering technology.

Instructions for Form #7244—Repowering Extension Plan Proposal

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. Unit Identification

A and B. Enter the Acid Rain Program Identification Number and the unit's short name from part I, sections A and B of the unit's permit application (SF# 72200A).

C. Emissions Data: Enter SO_2 emissions limitations information for the unit, including the SIP limit and the 1995 actual emission rate.

D. Indicate whether the unit will be repowered or replaced with a repowered unit.

E. If the unit will be replaced, for the proposed replacement unit

1. Enter the Acid Rain Program Identification Number.

2. Enter the unit's short name from Part I, Section B of the replacement unit's permit application (SF# 72200A).

II. Repowering Proposal

A. Identify the repowering technology that will be used at the repowered unit. If your technology is not listed at II A (1)-(5), mark (6).

B. For all technologies, indicate the status of the technology certification.

III. Activation of Plan

Mark the appropriate box to indicate whether you want the plan to go into effect upon approval, or whether you want to have the plan remain contingent. If you do not notify the Administrator by December 31, 1997 of a decision to activate the plan, the plan will be null and void after that date

IV. Repowering Compliance Schedule

Indicate the proposed dates for the listed increments of progress for the unit that will be repowered.

V. Standard Provisions and Prohibitions

Section V of the form lists limits and requirements applicable to any unit for which a repowering extension plan is approved. This section of the form does not require that you supply information. You should read it carefully.

VI. Certifications

The proposed designated representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See part III, section A of the Forms Instructions Package for more information about the legal effect of certification.

Instructions for Form #7244A—Repowering Technology Approval Request

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. Unit Identification

A and B. Enter the Acid Rain Program Identification Number and short name from part I, sections A and B of the unit permit application.

C. Indicate whether the unit will be repowered or replaced with a repowered unit.

D. If the unit will be replaced, for the proposed replacement unit, enter the Acid Rain Program Identification Number and the unit's short name from part I, sections A and B of the replacement unit's permit application (SF# 72200).

II. Repowering Proposal

A. Identify the repowering technology that will be used at the repowered unit. If the proposed technology is a qualified derivative of one of the technologies listed in (1)-(5), mark the box at 6, fill in the number of the listed technology, and complete part IIC. If your technology is not listed at IIA (1)-(6), mark (7) and complete IIC.

B. Mark this if you have marked (1)-(5) on the form, and attach the required vendor guarantee.

C. Mark this if you have marked (6) or (7) above, and attach the required vendor guarantee.

III. Standard Provisions and Prohibitions

Section III of the form lists limits and requirements applicable to any unit for which a repowering extension plan is approved. This section of the form does not require that you supply information. You should read it carefully.

IV. Certifications

The proposed designated representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See part III, section A of the Forms Instructions Package for more information about the legal effect of certification.

Instructions for Form #7244B—Notification of Removal From Operation To Install Repowering Technology

The Designated Representative must submit this form to EPA at least 60 days in advance of the date on which the affected unit that has been granted an extension is to be removed from operation to install the repowering technology.

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. Unit Identification

A and B. Enter the Acid Rain Program Identification Number and the unit's short name from part I, sections A and B of the unit permit application.

II. Notification

Provide the dates that the unit identified in part I will be removed from operation for installation of repowering technology or for permanent shutdown in the case of replacement with a new unit.

III. Standard Provisions and Prohibitions

Section III of the form lists limits and requirements applicable to any unit for which a repowering extension plan is approved. This section of the form does not require that you supply information. You should read it carefully.

IV. Certifications

The proposed designated representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See part III, section A of the Forms Instructions Package for more information about the legal effect of certification.

PART 73—SULFUR DIOXIDE ALLOWANCE SYSTEM

Authority: 42 U.S.C. 7651.

Subpart A—Background and Summary

§ 73.1 Purpose.

The purpose of this part is to establish the requirements and procedures for the following:

(a) The allocation of sulfur dioxide emissions allowances;

(b) The tracking, holding, and transfer of allowances;

(c) The use of allowances for purposes of compliance and for purposes of offsetting excess emissions pursuant to part 72 and part 77;

(d) The sale of allowances through EPA-sponsored auctions and a direct sale, including the independent power producers written guarantee program;

(e) The application for, and distribution of, allowances from the Conservation and Renewable Energy Reserve; and

(f) The qualifying measures and validation procedures for reduced utilization plans under part 72, § 72.43.

§ 73.2 Applicability.

The following parties shall be subject to the provisions of this part:

(a) Owners, operators, and designated representatives of sources deemed affected pursuant to § 72.7;

(b) Any new independent power producer as defined in Section 416 of the Act and this part, except as provided in Section 405(g)(6) of the Act;

(c) Any owner of an affected unit who may apply to receive allowances under the Energy Conservation and Renewable Energy Reserve Program established in Section 404(f) of the Act;

(d) Any small diesel refinery as defined in this part, and paragraph (e) of this section any other person, as defined in this part, who chooses to purchase, hold, or trade allowances as provided in Section 403(b) of the Act.

§ 73.3 Definitions.

The terms used in this part shall have the meaning given in the Act, as interpreted by this part and to CFR parts 73–78, and in this section as follows:

Account number means the identification number given to each allowance tracking system account pursuant to § 73.31(d).

Acid Rain Program means the sulfur dioxide and nitrogen oxides air pollution control program established pursuant to title IV of the Act under 40 CFR parts 72–78.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

Affected unit means a unit, or a source that opts in under 40 CFR part 74, that is subject to any emission reduction requirement or limitation under the Acid Rain Program.

Allowance means an authorization, allocated by the Administrator under the Acid Rain program, to emit up to one ton of sulfur dioxide, during or after a specified calendar year.

Allowance Tracking System means the system by which the Administrator allocates, issues, records, and tracks allowances.

Allowance Tracking System account means an account in the Allowance Tracking System established by the Administrator for the purposes of allocating, holding, transferring, and using allowances.

Allowance transfer deadline means midnight of January 30 or, if January 30 is not a business day, midnight of the first business day thereafter, and is the last day on which allowances may be submitted for recordation in an affected unit's compliance subaccount for the purposes of meeting sulfur dioxide emissions limitation requirements for the previous calendar year.

Alternate authorized account representative means the natural person designated in a certificate of representation submitted by an authorized account representative in accordance with subpart B of part 72 in the case of a unit account, or § 73.33 in the case of a non-unit account, to act on behalf of the authorized account representative with regard to all matters within the authority of the authorized account representative under this part.

Authorized account representative means a natural person who may transfer and otherwise dispose of allowances held in an account in the Allowance Tracking System, including, in the case of a unit account, the designated representative of the owners and operators of an affected unit.

Certifying official, for purposes of part 73, means:

(1) For a corporation, a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy- or decision-making functions for the corporation;

(2) For a partnership or sole proprietorship, a general partner or the proprietor, respectively; and

(3) For a local government entity or, State, Federal, or other public agency, either a principal executive officer or ranking elected official.

Compliance subaccount means an affected unit's Allowance Tracking System subaccount in which are held, (1) from the date that allowances usable in the current calendar year are recorded under § 73.34(a) through December 31, allowances that may be used for compliance for the current calendar year and, (2) after December 31 until the date that deductions are made under § 73.35(b), allowances that may be used for compliance for the preceding calendar year.

Compliance use date means the first calendar year for which an allowance may be used for purposes of meeting a unit's sulfur dioxide emissions limitation requirements.

Current year subaccount means the subaccount in an Allowance Tracking System non-unit account in which are held allowances that may be transferred for the purpose of meeting a unit's sulfur dioxide emissions limitation requirements in the current calendar year until December 31, and after December 31 until the date that deductions are made under § 73.35(b), for the purpose of meeting such requirements in the preceding year.

Customer means a purchaser of electricity not for purposes of transmission or resale.

Demand-side measures means measures to improve the efficiency of consumption of electricity by customers of an electric utility and includes the resources set forth in appendix B(1) of this part.

Designated representative means a natural person authorized by the owners and operators of a source and of all affected units at the sources, as evidenced by a certificate of representation submitted in accordance with 40 CFR part 72, subpart B to represent and legally bind the owners and operators jointly and severally as a matter of federal law in all matters pertaining to the Acid Rain Program. Whenever the term "responsible official" is used in 40 CFR part 70 or 71 or in a State operating permit program approved pursuant to title V of the Act and 40 CFR part 70, it shall be deemed to refer to the "designated representative" as defined here in so far as Acid Rain Program actions, standards, requirements, or prohibitions are concerned.

Electric utility means any person, State agency, or Federal agency that sells electric energy.

EPA Conservation Verification Protocol means a methodology developed by the Administrator pursuant to § 73.82(c) to be used in calculating the electricity saved from energy conservation and improved unit efficiency measures for the purposes of title IV of the Act.

Existing affected unit, means, for purposes of part 73, a unit that is both an affected unit and an existing unit, as defined in this part.

Existing unit, means a unit (including a unit subject to section 111 of the Act) that commenced commercial operation before November 15, 1990. Any unit that commenced commercial operation before November 15, 1990 and that is modified, reconstructed, or repowered after November 15, 1990 shall continue to be an existing unit. Existing units do not include simple combustion turbines, or units that serve only a generator with a nameplate capacity of 25 MWe or less.

First-in, first-out accounting basis, or FIFO, means the following order for the purposes of allowance deductions pursuant to § 73.35(b):

(1) Allowances originally allocated for the unit and recorded in the unit's compliance subaccount pursuant to subpart C of this part, beginning with those with the earliest compliance use date, and followed by

(2) Those allowances allocated for other units and recorded in the unit's compliance subaccount pursuant to subpart D, beginning with those with the earliest date of recordation.

Future year subaccount means a subaccount in an Allowance Tracking System account in which allowances are held for one of the 30 years following the later of 1995 or a current calendar year following 1995.

Hybrid generating facility means a plant that generates electricity using a combination of renewable energy (wind, solar, biomass, or geothermal) and non-renewable energy resources.

Least cost plan means a least cost energy conservation and electric power planning methodology employed by an electric utility that evaluates the full range of existing and incremental resources in order to meet expected future demand at lowest system cost. These resources include but are not limited to, new power supplies, energy conservation, load management, and renewable energy resources.

Load management means economic reduction of electric energy demand during a utility's peak generating periods.

Net income neutrality means, in the case of energy conservation measures undertaken by an electric utility whose rates are regulated by a State regulatory authority, rates and charges established by the State regulatory authority that ensure that the net income earned by the utility on the book value of its State-jurisdictional equity investment will be no lower as a consequence of its expenditures on qualified cost-effective energy conservation measures and any associated lost sales than it would have been had the utility not made such expenditures.

Non-unit account means an Allowance Tracking System account that is not a unit account.

Period of applicability means the period on or after January 1, 1992 and before the earlier of:

(1) December 31, 2000, or

(2) The date on which any unit that is owned or operated by an electric utility becomes an affected unit.

Person means an individual, corporation, partnership, association, State, municipality, political subdivision of a State, and any agency, department, or instrumentality of the United States and any officer, agent, or employee thereof.

Process source shall have the meaning provided in 40 CFR part 74.

Receive or *receipt of* means the coming into possession of a request or notification transmitted by certified United States Mail, with the indication of its official postmark, or by other means, with an equivalent official time and date mark to indicate the time of dispatch and a record of delivery.

Recordation means the official deposit or withdrawal of allowances, by the Administrator, in or from an account or subaccount in the Allowance Tracking System.

Reduced utilization means a reduction, during any calendar year during Phase I, in the annual average heat input at an affected unit, below the unit's baseline, where such reduction subjects the unit to the requirements of § 72.43.

Renewable energy input means the quantity of biomass, solar, geothermal, or wind resources (in Btu's) consumed in the process of generating electricity (in kilowatt hours).

Secretary of Energy means the Secretary of the United States Department of Energy or the Secretary's duly authorized representative.

Serial number means the unique identification number assigned to each allowance by the Administrator, pursuant to § 73.34(d).

Small diesel refinery (reserved).

State regulatory authority means a state-based authority or commission responsible for oversight of the operations of electric utilities, including, but not limited to, rates and charges to customers.

Submit means to send or to transmit information or correspondence in writing by certified United States Mail, with the indication of its official postmark, or by other means, with an equivalent official time and date mark to indicate the time of dispatch and a record of delivery.

Supply-side measures means measures to improve the efficiency of activities or facilities used by an electric utility to provide electricity to its customers and includes the measures set forth in appendix B(2) of this part.

Sulfur dioxide emissions limitation requirements means the limitation on sulfur dioxide emissions specified for an affected unit in section 403, section 404, or section 405 of the Act or in the unit's permit.

Transferee account means the Allowance Tracking System account to which allowances are being transferred.

Transferror account means the Allowance Tracking System account from which allowances are being transferred.

Transferror unit account means a unit account that is a transferror account.

Unit account means an Allowance Tracking System account that is established for an affected unit.

Use of allowances means the deduction and consumption of allowances to offset sulfur dioxide emissions in compliance with sulfur dioxide emissions limitation requirements.

§ 73.4 Deadlines.

In any year in which the deadline for an action authorized or required under this part falls on a non-business day, the deadline will be the first business day after the date stated in this part.

Subpart B—Allowance Allocations

§§ 73.11–73.29 Allowance calculations and tables. [Reserved]

Subpart C—Allowance Tracking System

§ 73.30 Allowance tracking system accounts.

(a) *Nature and function of unit accounts.* The Administrator will establish accounts for all affected units pursuant to § 73.31 (a) and (b) and part 74. All allocations of allowances pursuant to subparts A and E and parts 72 and 74, transfers of allowances made pursuant to subparts C and D, and deductions of allowances made for purposes of offsetting emissions pursuant to § 73.35 (b) and (f) and part

77 will be recorded in the unit's Allowance Tracking System account.

(b) *Nature and function of non-unit accounts.* Transfers of allowances held for any person other than an affected unit, made pursuant to subparts C, D, E, and F, will be recorded in that person's Allowance Tracking System account established pursuant to § 73.31(c).

§ 73.31 Establishment of accounts.

(a) *Existing affected units.* (1) Not later than January 30, 1993, the Administrator will establish an Allowance Tracking System account for each unit that is, or will become, an existing affected unit pursuant to section 404(a) or section 405 of the Act;

(2) (i) For units that become affected units pursuant to section 404(b), section 404(c), and section 408(c)(1)(B) of the Act and § 72.42 and § 72.43, the Administrator will establish unit accounts pursuant to § 72.42 and § 72.43; and

(ii) For sources that become affected units pursuant to § 72.49 and part 74, the Administrator will establish a unit account for each unit.

(b) *New units.* Upon receipt of a valid certificate of representation for a new unit pursuant to part 72, the Administrator will establish an Allowance Tracking System account for the unit.

(c) *Non-unit accounts.* (1) Any person may apply to open an Allowance Tracking System account for the purpose of holding and transferring allowances. Such application shall be submitted to the Administrator by means of the New Account/New Authorized Account Representative Form, in appendix A of this part, which will include, at a minimum:

(i) Name and title of the authorized account representative pursuant to § 73.33;

(ii) Mailing address, telephone number and facsimile transmission number, if any, of the authorized account representative;

(iii) Organization or company name (if applicable) and type of organization (if applicable); and

(iv) Certification by the authorized account representative pursuant to § 73.33(c).

(2) Upon receipt of such application, the Administrator will establish an Allowance Tracking System account for the person identified in the application pursuant to § 73.33(b) and (c).

(d) *Account identification.* The Administrator will assign a unique identifying number to each account established pursuant to this section.

§ 73.32 Allowance account contents.

Each allowance account will include, at a minimum, the following:

(a) The name, address, telephone number and facsimile transmission number, if any, of the authorized account representative and, in the case of a unit account, a list of all persons identified as owners of record in § 72.20(c)(4), or, in the case of a non-unit account, a list of all persons with an ownership interest identified in § 73.33(c)(1);

(b) A list of all transfers of allowances to, and from, the account, including the identity of the transferror and transferee accounts;

(c) In the case of a unit account for an existing affected unit, beginning in 1995, a compliance subaccount;

(d) In the case of a unit account for a new unit, a compliance subaccount;

(e) In the case of a non-unit account, a current year subaccount;

(f) Future year subaccounts for each of the 30 calendar years following the later of 1995 or the current calendar year;

(g) In the case of a unit account, the current total of sulfur dioxide emissions in tons for the current calendar year as reported to date pursuant to part 75.

§ 73.33 Authorized account representative.

Following the establishment of an Allowance Tracking System account, all matters pertaining to the account, including, but not limited to, the use and transfer of allowances in the account, shall be undertaken only by the authorized account representative.

(a) *Unit accounts.* For purposes of accounts for affected units, the authorized account representative shall be the designated representative for the unit certified pursuant to § 72.20 and shall be subject to the requirements of subpart B of part 72.

(b) *Non-unit accounts.* For purposes of a non-unit account, the authorized account representative shall be the person authorized in the application for opening the account submitted pursuant to § 73.31(c), which may be modified pursuant to paragraph (e) of this section.

(c) *Certificate of representation for the authorized account representative.* No allowance transfers will be recorded for a non-unit account until the authorized account representative has signed a certificate of representation on the New Account/New Authorized Account Representative Form and the Administrator has established the new account. The certificate of representation shall include:

(1) A list of all persons with an ownership interest with respect to the allowances held in the non-unit account and which shall be amended and resubmitted within 30 days following any transaction giving rise to any change of ownership interest, by means of a New Account/New Authorized Account Representative Form;

(2) A statement that the representative was selected by an agreement binding on all persons who have an ownership interest with respect to the allowances held in the non-unit account that includes a specification of the terms and conditions under which an alternate authorized account representative, if any, is to act in place of the authorized account representative;

(3) A statement that the authorized account representative has all necessary authority to carry out the duties and responsibilities of the authorized account representative as enumerated in this part;

(4) A statement that the authorized account representative will abide by the fiduciary responsibilities assigned pursuant to the binding agreement. Where only one person has ownership interest with respect to the allowances in an account, the certification shall state that all allowances in the account are deemed to be held for that person.

(d) *Alternate authorized account representative.* For a non-unit account, the certificate of representation may designate one alternate authorized account representative to act on behalf of the certifying authorized account representative in the event the authorized account representative is absent or otherwise not available to perform actions or duties specified in this part. The alternate shall be a natural person and shall be authorized provided that: the conditions and procedures of the certificate of representation, specified in paragaph (c) of this section are met, and:

(1) In the event of a conflict, any action taken or submission made by the authorized account representative shall take precedence over any action taken by the alternate authorized account representative if, in the Administrator's judgment, the actions are concurrent and conflicting;

(2) The alternate authorized account representative may be changed at any time by the authorized account representative upon submission of a new certificate of representation to the Administrator as provided in paragraph (c) of this section.

(3) The alternate authorized account representative shall be subject to the provisions of this part;

(4) Whenever the term "authorized account representative" is used in this part it shall be construed to include the alternate authorized account representative, unless such a construction would be illogical from the context; and

(5) Any action, representation or failure to act by the alternate authorized account representative when acting in that capacity shall be deemed to be an action of the authorized account representative, with all the rights, duties, and responsibilities pertaining thereto.

(e) *Changes to the authorized account representative.* An authorized account representative for a non-unit account may be succeeded by any person who submits a New Account/New Authorized Account Representative Form and certification pursuant to paragraph (c) of this section. The actions of an authorized account representative for a non-unit account shall be binding on any successor.

(f) *Objections to the authorized account representative.* Except for a certification pursuant to paragraph (e) of this section, no objection or other communication submitted to the Administrator concerning any submission to the Administrator by the authorized account representative shall affect the recordation of transfers submitted by the authorized account representative pursuant to subpart D. Neither the United States, the Administrator, nor any permitting authority will adjudicate any dispute between and among persons concerning any submission to the Administrator by the authorized account representative; any actions of the authorized account representative; or any other matter arising directly or indirectly from the certification, actions or representations of the authorized account representative.

§ 73.34 Recordation in accounts.

(a) *Recordation in compliance subaccounts.* At the beginning of 1995 and, in the case of each year thereafter, after the Administrator has made all deductions from a unit compliance subaccount pursuant to § 73.35(b), the Administrator will record in the compliance subaccount established for each unit pursuant to § 73.31(a) and § 73.31(b) the allowances held in the future year subaccount for the year corresponding to the current calendar year.

(b) *Recordation in future year subaccounts.* Allowances in each future year subaccount for each existing affected unit will reflect:

(1) All allowances allocated for the unit for the year pursuant to subpart B;

(2) All allowances allocated pursuant to § 72.41;

(3) All allowances allocated pursuant to § 72.42;

(4) All allowances allocated pursuant to § 72.43;

(5) All allowances allocated pursuant to § 72.44;

(6) All allowances allocated pursuant to subpart F;

(7) In the case of a unit or process source subject to the provisions of part 74, all allowances allocated pursuant to part 74;

(8) All allowances added as a result of purchases from the annual auctions or direct sale pursuant to subpart E;

(9) All allowances added or deducted as a result of allowance transfers recorded pursuant to subpart D; and

(10) All allowances deducted pursuant to § 73.35(e) and part 77.

(c) *Recordation in current year subaccounts.* At the beginning of 1995 and each year thereafter, the Administrator will record in the current year subaccount established for non-units pursuant to § 73.31(c) the allowances held in the future year subaccount for the year corresponding to the current calendar year.

(d) *Serial numbers for allocated allowances.* Upon the allocation of allowances for an existing affected unit pursuant to subpart B and the allocation of allowances pursuant to §§ 72.41, 72.42, 72.43, and 72.44 and part 74, the Administrator will assign each allowance a unique identification number.

(e) *Serial numbers for allowances in Reserves.* The Administrator will assign a unique identification number to each allowance transferred to an account from a reserve established pursuant to the requirements of sections 404(a)(2), 404(g), and 416(b) of the Act and subpart B.

§ 73.35 Compliance.

(a) *Allowance transfer deadline.* (1) No allowance shall be used for purposes of compliance with a unit's sulfur dioxide emissions limitation requirements pursuant to title IV of the Act and paragraph (b) of this section unless:

(i) The compliance use date of the allowance is no later than the year in which the unit's SO_2 emissions occurred; and

(ii) By no later than the allowance transfer deadline, such allowance is recorded in the compliance subaccount or its transfer into the compliance subaccount is properly submitted for recordation in the compliance subaccount for the unit in accordance with the requirements of subpart D.

(2) The date of submission shall be the time of receipt as indicated by a time and date mark in the case of certified mail or by electronic transmission capable of indicating the time of receipt by the Administrator, in the case of a submission by electronic method.

(b) *Deductions for compliance.* (1) Except as provided in paragraph (e) of this section, following the recordation of transfers properly submitted for recordation in the compliance subaccount pursuant to paragraph (a) of this section and subpart D, the Administrator will deduct from each affected unit's compliance subaccount allowances equal in amount to the sum of:

(i) The unit's sulfur dioxide emissions tonnage during the immediately preceding calendar year as reported pursuant to part 75; and

(ii) In the case of a unit subject to the requirements of § 72.43, the sulfur dioxide emissions tonnage during the immediately preceding calendar year resulting from any compensating generation, pursuant to § 72.43 and subpart K of part 72.

(2) The Administrator will make deductions until either the number of allowances deducted is equal in amount to the sum of the unit's sulfur dioxide emissions tonnage during the immediately preceding calendar year, calculated pursuant to paragraph (b)(2) (i) and (ii) of this paragraph, or until no more allowances remain in the subaccount. Following such deduction, the account will state the unit's excess emissions, if any.

(c) *Identification of allowances by serial number.* By no later than the allowance transfer deadline for the compliance subaccount, the authorized account representative for each unit account may identify by serial number the allowances to be deducted from the compliance subaccount for purposes of compliance with the unit's sulfur dioxide emissions limitation requirements. Such identification shall be made by submission of the Compliance Deduction Form, in appendix A of this part, or by such electronic method as the Administrator may prescribe in the future.

(d) *First-in, first-out.* In the absence of an identification of allowances by serial number, as provided for in paragraph (c) of this section, the Administrator will deduct allowances on a first-in, first-out (FIFO) accounting basis beginning with those allowances with the earliest compliance use date originally allocated for the unit and recorded in its

compliance subaccount, and followed by those allowances allocated for other units and recorded in the unit's compliance subaccount account pursuant to Subpart D, beginning with those with the earliest date of recordation.

(e) *Deductions for excess emissions.* Unless otherwise provided in an approved excess emissions offset plan pursuant to part 77, and following the process of recordation set forth in § 73.34(a), the Administrator, pursuant to part 77, will deduct from the compliance subaccount, for each unit with excess emissions for the preceding calendar year, allowances in an amount equal to the unit's excess emissions tonnage. The authorized account representative may identify by serial number in the excess emissions offset plan submitted pursuant to part 77 the allowances to be deducted from the compliance subaccount. In the absence of such specification, the method for identifying allowances to be deducted pursuant to this section will be determined at the discretion of the Administrator.

(f) *Units subject to common emission stack plans.* In the case of units subject to a common stack plan pursuant to §§ 75.11(a) and 72.50, the Administrator will aggregate the allowances recorded in the compliance subaccounts for all the units governed by the plan for purposes of making deductions pursuant to paragraphs (b) and (e) of this section. The Administrator will record in each unit's compliance subaccount each unit's per capita share, adjusted to the nearest allowance, of any aggregated allowances remaining following deductions made pursuant to paragraphs (b) and (e) of this section.

(g) *Units subject to amended Phase I substitution and compensating unit plans.* Following an administrative amendment to a compliance plan pursuant to § 72.303(a)(11) with respect to unit(s) subject to a Phase I Substitution Plan or Phase I Compensating Unit Plan, the Administrator will deduct from the accounts of such unit(s) allowances recorded pursuant to § 72.41(c)(2) in the case of a substitution plan or § 72.43(b)(2) in the case of a compensating unit plan.

§ 73.36 Banking.

(a) *Unit accounts.* Any allowance not deducted pursuant to § 73.35 will remain in the compliance subaccount.

(b) *Non-unit accounts.* In the case of a non-unit account, any allowances in the current year subaccount at the end of the current calendar year will remain in the current year subaccount until transferred to another account pursuant to §§ 73.52 and 73.53.

§ 73.37 Account error and dispute resolution.

(a) *Claim of error.* The authorized account representative may notify the Administrator of any claim that there is an error in an Allowance Tracking System account, provided that such notification is received by the Administrator by no later than either 20 business days following the submission of the transfer that is the subject of the notification or 10 business days following notification pursuant to § 73.54 or § 73.55, and that where such claim involves allowances transferred to or from a compliance subaccount, such notification shall be received by the Administrator by no later than 15 business days following the allowance transfer deadline. Such notification shall be in writing and shall include:

(1) A description of the alleged error;

(2) A proposed correction of the alleged error;

(3) Any supporting documentation or other information concerning the alleged error and proposed correction; and

(4) Certification by the authorized account representative. The Administrator will not act on notifications received after the stated deadlines.

(b) *EPA action.* The Administrator, at the Administrator's sole discretion, will determine what changes, if any, will be made to the accounts subject to the alleged error. Not later than 30 days after receipt of notification pursuant to paragraph (a) of this section, the Administrator will submit to the authorized account representative a written response stating:

(1) The determination made and any action taken by the Administrator; and

(2) The reasons for such action.

(c) *Appeal for reconsideration.* The authorized account representative may appeal for reconsideration of the Administrator's denial, in whole or in part, of any claim that there is an error in an Allowance Tracking System account, by resubmitting the claim and the request, provided that the request for appeal is received by the Administrator by no later than 15 business days following the authorized account representative's receipt of notification of the Administrator's decision on the submitted error claim, and that where such claim involves allowances transferred to or from a compliance subaccount, such appeal shall be received by the Administrator by no later than 15 business days following the allowance transfer deadline. An authorized account representative may make only one appeal for reconsideration of a determination on a claim of error.

(d) *EPA corrections.* The Administrator may, without prior notice and at the Administrator's sole discretion, correct any errors in any account. The Administrator will notify the authorized account representative by no later than 30 days following such corrections.

(e) *Excess emissions requirements.* The filing of notification pursuant to paragraph (a) of this section or the pendency of the Administrator's action pursuant to paragraph (b) of this section shall not affect a unit's obligations under Part 77.

(f) *Waiver of Deadline.* The Administrator may, in his or her discretion, accept submissions made following the deadlines imposed in this section upon a demonstration by the authorized account representative of good cause for the delay. The finding of whether good cause exists shall be in the sole discretion of the Administrator.

§ 73.38 Public availability.

Any person may review information compiled pursuant to § 73.34 in the Allowance Tracking System. In the future, the Administrator will prescribe, following public notice, a method of electronic communication for reviewing such information.

§ 73.39 Closing of accounts.

(a) *Non-unit accounts.* The authorized account representative of a non-unit account may instruct the Administrator to close the non-unit account by submitting a valid Allowance Transfer Form, in Appendix A of this Part, pursuant to § 73.52 and § 73.53, requesting the transfer of all allowances held in the account into another account in the Allowance Tracking System, and submitting in writing, with the signature of the authorized account representative, a request to delete the non-unit account from the Allowance Tracking System.

(b) *Inactive accounts.* If a non-unit account shows no activity for a period of a year or more and does not contain any allowances in its subaccounts, the Administrator will notify the account's authorized account representative that the account will be closed and eliminated from the Allowance Tracking System following 20 business days from the date the notice is sent. The account will be closed following the 20-day period, unless the Administrator receives and approves a request for recordation of the transfer of allowances into the account pursuant to § 73.52, or

the authorized account representative submits, in writing, demonstration of good cause as to why the inactive account should not be closed. The finding of good cause is at the sole discretion of the Administrator.

Subpart D—Allowance Transfers

§ 73.50 Scope of transfers.

(a) Except as provided in § 73.51, the Administrator will record transfers of an allowance to and from Allowance Tracking System accounts, including, but not limited to, transfers of an allowance to and from contemporaneous future year subaccounts, and transfers of an allowance to and from compliance subaccounts and current year subaccounts, and transfers of all allowances allocated for a unit for each calendar year in perpetuity, provided that:

(1) Such transfers are authorized and certified in writing by the submission of a completed Allowance Transfer Form, or by such other method as the Administrator, through public notice, may prescribe in the future, by the authorized account representatives for both the transferror account and the transferee account;

(2) Each allowance identified by serial number specified pursuant to § 73.52(a)(2) is in the transferror account, except when a request for transfer of the unit's allowances in perpetuity is indicated correctly on the Allowance Transfer Form;

(3) Allowances identified by serial number specified pursuant to § 73.52(a)(2) are not subject to the limitations imposed pursuant to § 72.44(f)(3)(i), and on opt-in sources reducing utilization pursuant to Part 74;

(4)(i) In the case of a transferror unit account for which a transfer is submitted for recordation in a compliance subaccount and:

(A) The unit had excess sulfur dioxide emissions in the immediately preceding calendar year, and

(B) The Administrator has not approved the unit's excess emissions offset plan or deducted allowances pursuant thereto from the unit's account,

(ii) No transfer will be recorded unless the total number of allowances in the compliance subaccount exceeds the sum of:

(A) The number of allowances subject to the transfer, and

(B) The unit's excess emissions in the immediately preceding calendar year; and

(5) Transfers of allowances in compliance subaccounts submitted for recordation following the allowance transfer deadline will not be recorded until after completion of the process of recordation set forth in § 73.34(a).

(b) Notwithstanding any action by the Administrator following the submission of a transfer for recordation, it shall be unlawful within the meaning of section 414 of the Act for any person to submit to the Administrator a transfer for recordation that fails to meet the requirements of paragraph (a) of this section.

§ 73.51 Prohibition.

Except as provided in § 73.34(a), the Administrator will not record a transfer of allowances from a future year subaccount to a subaccount for an earlier year.

§ 73.52 Submission of transfers.

(a) Authorized account representatives seeking recordation of a transfer of allowances shall submit to the Administrator an Allowance Transfer Form which shall, at a minimum, include:

(1) The numbers identifying both the transferror and transferee accounts;

(2) A specification by serial number of each allowance to be transferred;

(3) Signatures of the authorized account representatives of both the transferror and transferee account;

(4) Where the transferee account has not been established, information as required pursuant to § 73.31 (b) or (c); and

(5) Where the transfer involves a unit account, certification of acknowledgement by the authorized account representative that no action the Administrator may take with respect to the requested transfer affects the unit's obligation to comply with its annual sulfur dioxide emissions limitation requirements.

(b) Following public notice, the Administrator may prescribe in the future alternative methods for submission of an allowance transfer for recordation.

§ 73.53 EPA recordation.

Except as provided in § 73.50 and § 73.51, the Administrator will record an allowance transfer by no later than five business days following receipt of information pursuant to § 73.52, by deducting each allowance from the transferror account and adding it to the transferee account as specified pursuant to § 73.52, provided that:

(a) The information submitted pursuant to § 73.52 is complete;

(b) The transferror account includes each allowance identified by serial number in the information submitted pursuant to § 73.52; and

(c) The transfer meets all applicable requirements of this Subpart.

§ 73.54 Notification.

The Administrator will give notice of an allowance transfer within five business days following the recordation of the transfer. Notice will be in writing or by such other method as the Administrator may prescribe in the future following public notice, to the authorized account representatives of both the transferror and transferee accounts.

§ 73.55 Non-recordation of transfers.

(a) *Notification of non-recordation.* (1) Where an allowance transfer submitted for recordation fails to meet the requirements of this Subpart, the Administrator will not record such transfer. By no later than five business days following receipt of the Allowance Transfer Form by the Administrator, the Administrator will notify, in writing or by such electronic method as the Administrator will prescribe in the future through public notice, the authorized account representatives of the accounts subject to the allowance transfer submitted for recordation of:

(i) Such non-recordation, and

(ii) The reasons for such non-recordation.

(2) Nothing in this section shall preclude the submission of a transfer for recordation following such notification.

(b) *Administrator's discretion not to record.* Notwithstanding any other provision of this Subpart, the Administrator, at the Administrator's sole discretion, may determine not to record a transfer where the transferror account is for a unit with excess emissions in the calendar year preceding the date on which the transfer is submitted or is subject to a proposed or approved compliance plan pursuant to the requirements of part 77.

Subpart E—Auctions, Direct Sales, and Independent Power Producers Written Guarantee

Note: Subpart E was previously published May 23, 1991 in 40 CFR part 73, at 56 FR 23754–23759, as subpart D, and is now renamed as subpart E.

Subpart F—Energy Conservation and Renewable Energy Reserve

§ 73.80 Operation of allowance reserve program for conservation and renewable energy.

(a) *General.* Upon approval of applications submitted by one or more electric utilities, for each ton of sulfur dioxide emissions deemed to have been avoided during the period of

applicability through the use of one or more qualified energy conservation measures or of qualified renewable energy generation during a previous calendar year or years, the Administrator will allocate a single allowance from the Conservation and Renewable Energy Reserve (the "Reserve") in the order in which applications are received until a total of 300,000 allowances have been allocated.

(b) *Period of applicability.* Allowances will be allocated under this Subpart for energy conservation measures or renewable energy generation sources that are operational after January 1, 1992, and before the earlier of December 31, 2000 or the date on which any unit owned or operated by the applicant becomes an affected unit under Title IV.

(c) *Termination of the Reserve.* The Administrator will allocate any allowances remaining in the Reserve after January 2, 2010 to affected units under Section 405 of the Act from whom allowances were withheld for purposes of establishing the Reserve. Each unit's allocation will be calculated as follows:

Remaining Allowances in the Reserve × Unit's Allowances Withheld

Total Amount in Reserve

(Allowances will be rounded to the nearest allowance)

§ 73.81 Qualifying conservation measures and renewable energy generation.

(a) *Qualified energy conservation measures.* A qualified energy conservation measure is a material or device not operational until the period of applicability, installed in the residence or facility of a customer to whom the electric utility sells electricity, that:

(1) Is specified in appendix B(1); or

(2) In the case of a device or material that is not included in Appendix B(1), is a cost-effective demand-side measure consistent with an applicable least-cost plan that increases the efficiency of the customer's use of electricity (as measured in accordance with applicable State verification procedures or protocol or with the EPA Conservation Verification Protocol) without increasing the use by the customer of any fuel other than qualified renewable energy, industrial waste heat, or industrial waste gases; and

(i) Is approved by the State regulatory authority that regulates the rates of the applicant; or

(ii) Is approved by the Administrator, when the applicant is an electric utility whose rates are not regulated by a State regulatory authority.

(b) *Non-qualifying energy conservation measures.* Qualified energy conservation measures shall not include:

(1) Measures that were operational before January 1, 1992;

(2) Supply-side measures;

(3) Conservation programs that are exclusively informational or educational in nature; or

(4) Load management, unless kilowatt hour savings can be verified by the electric utility pursuant to § 73.82(c).

(c) *Qualified renewable energy generation.* Qualified renewable energy generation is electric generation, not operational until the period of applicability, that:

(1) Is specified in appendix B(3); or

(2) In the case of renewable energy generation that is not included in appendix B(3), is energy generation derived from biomass (*i.e.*, combustible energy-producing materials from biological sources which include wood, plant residues, biological wastes, landfill gas, energy crops, and eligible components of municipal solid waste), solar, geothermal, or wind resources and

(i) Is approved by the State regulatory authority that regulates the rates of the applicant; or

(ii) Is approved by the Administrator, when the applicant is an electric utility whose rates are not regulated by a State regulatory authority.

(d) *Non-qualifying renewable energy generation.* Qualified renewable energy generation shall not include:

(1) Renewable energy generation that was operational before January 1, 1992;

(2) Measures that do not generate electricity directly, including but not limited to measures that may reduce electricity demand without providing electric generation directly to the electric utility for sale to customers; and

(3) Measures that appear on the list of qualified energy conservation measures in appendix B(1).

§ 73.82 Application for allowances from reserve program.

(a) *Application requirements.* Each application for Conservation and Renewable Energy Reserve allowances, as included in appendix A of this part, and accompanying documentation, shall demonstrate that:

(1) The applicant, or any subsidiary of the applicant, owns or operates, in whole or in part, at least one affected unit or is a utility or industrial customer which purchases power from an affected unit (or units) under "life-of-the-unit" firm power contractual arrangements as defined in section 402(27) of the Act (the applicant shall list the name and Allowance Tracking System account number of an affected unit which it owns or operates);

(2) The applicant is paying in whole or in part for qualified conservation measures or qualified renewable energy generation (implemented during the period of applicability) either directly or through payment to another person that purchases the qualified conservation measure or qualified renewable energy generation (the applicant shall specify the amount spent on the conservation measure or the renewable energy generation);

(3) The qualified energy conservation measure adopted or qualified renewable energy generated, or both, do not result in any net increase in sulfur dioxide emissions (the applicant shall certify that this requirement was met);

(4) The applicant has prepared, pursuant to a least-cost planning process that provides an opportunity for public notice and comment, and the applicant is implementing to the maximum extent practicable, a least cost plan that treats demand-side resources and supply-side resources on a consistent and integrated basis; takes into account necessary features for system operation such as diversity, reliability, dispatchability, and other factors of risk; and that may take into account other factors, including the social and environmental costs and benefits of resource investments;

(5) The qualified energy conservation measure adopted or qualified renewable energy generated, or both, are consistent with the least cost plan;

(6) If the applicant is subject to the rate-making jurisdiction of a State regulatory authority, its least cost plan has been approved and such approval has been certified by the regulatory authority in the State in which the qualifying conservation measures are adopted or in which the renewable energy generation is utilized;

(7) If the applicant is not subject to the rate-making jurisdiction of a State regulatory authority, its least cost plan has been approved and certified by the entity with rate-making authority for such utility for the State in which the qualifying conservation measures are adopted or in which the renewable energy generation is utilized;

(8) If the applicant is not subject to the jurisdiction of an entity with ratemaking authority, the applicant has enclosed a copy of its least cost plan with its application for approval by the Administrator;

(9)(i) If the applicant is subject to the ratemaking jurisdiction of a State regulatory authority and is submitting an application on the basis of qualified

energy conservation measures, such State regulatory authority has established rates and charges ensuring that the utility's net income is compensated in full (considering factors such as risk) for lost sales attributable to the electric utility's conservation programs, which rates and charges may include:

(A) General rate-making formulas that decouple utility profits from actual utility sales;

(B) Specific rate adjustment formulas that allow a utility to recover in its retail rates the full costs of conservation measures plus any associated net revenues lost as a result of reduced sales resulting from conservation initiatives; and

(C) Conservation incentive mechanisms designed to provide positive financial rewards to a utility to encourage implementation of cost-effective measures; and

(ii) Pursuant to paragraph (b) of this section, the Secretary of Energy has certified the establishment of such net income neutrality;

(10) The applicant has implemented qualified energy conservation measures identified in the application and/or used qualified renewable energy generation specified in the application for purposes of avoiding emissions during the period of applicability;

(11) The installation of qualified conservation measures has achieved actual energy savings, by stating, on the basis of their performance following installation:

(i) The amount of energy savings (in kilowatt hours) resulting from the measures per year;

(ii) Pursuant to paragraph (c) of this section, the methodology used to calculate the savings; and

(iii) The name of the person who performed the calculation;

(12) The amount of yearly qualified renewable energy generation has achieved actual energy savings, by stating (and submitting documentation, including copies of plant operation records, supporting such statements):

(i) The hours of operation (on a BTU basis) during a previous calendar year or years; and

(ii) The nameplate capacity, in megawatts, of the renewable generation facility;

(13) Qualified renewable energy generation using a hybrid generating facility, including, but not limited to, a municipal solid waste combustion facility, has achieved actual energy savings, by stating (and submitting documentation, including copies of plant operation records, supporting such statements):

(i) The quantity of renewable energy input (on a Btu basis) and the portion of electric generation that can be attributed to that renewable energy input; and

(ii) The nameplate capacity, in megawatts, of the hybrid renewable generation facility;

(14) The implementation of qualified energy conservation measures or the use of qualified renewable energy generation has resulted in avoided sulfur dioxide emissions during the period of applicability, by stating the number of tons avoided as calculated pursuant to paragraph (d) of this section.

(b) *Application to the Secretary of Energy.* (1) Using Supplement A of the Application for Energy Conservation and Renewable Energy Reserve Allowances, for purposes of this paragraph and paragraph (a)(9)(ii) of this section, the applicant shall submit to the Secretary of Energy:

(i) A copy of the relevant State regulatory authority's final order or decision setting forth the approved rate-making mechanisms that ensure that an electric utility's net income will be at least as high upon implementation of conservation measures as such net income would have been if the energy conservation measures had not been implemented;

(ii) A description of how the order or decision meets the definition of net income neutrality as defined in these regulations; and

(iii) Any additional information necessary for the Secretary of Energy to certify that the State regulatory authority has established rates and charges that ensure net income neutrality.

(2) If an electric utility applying for allowances from the Reserve has already received certification of net income neutrality from the Secretary of Energy in connection with a previous application for allowances, and the rate-making methods or procedures that ensure net income neutrality have not been altered, the applicant shall indicate in Supplement A of the application form that the rate-making methods and procedures that led to the original certification are still in place.

(c) *Verification of qualified conservation measures.* For the purposes of paragraph (a)(11) of this section:

(1) Applicants subject to the ratemaking jurisdiction of a State regulatory authority shall use the verification methodology approved by such authority;

(2) Applicants whose rates are not subject to the ratemaking jurisdiction of a State regulatory authority shall use the EPA Conservation Verification Protocol, copies of which will be available from the Administrator at the address listed in paragraph (e) of this section.

(3) The Administrator reserves the right to conduct independent audits to ascertain that the verification is valid and correct.

(d) *Calculation of allowances to be allocated.* For purposes of paragraph (a)(10) of this section:

(1) In the case of an application submitted on the basis of qualified energy conservation measures, the sulfur dioxide emissions tonnage deemed avoided for any calendar year shall be equal to the product of:

$$\frac{(A)\times(B)}{2000\ \text{lbs.}}$$

(Rounded to the nearest ton)

Where:

(i) = the kilowatt hours that were not, but would otherwise have been, supplied by the utility during such year in the absence of such qualified energy conservation measures.

(ii) = 0.004 lbs. per kilowatt hour.

(2) In the case of an application submitted on the basis of qualified renewable energy generation, the emission tonnage deemed avoided for any calendar year shall be equal to the product of:

$$\frac{(A)\times(B)}{2000\ \text{lbs.}}$$

(Rounded to the nearest ton)

Where:

(i) = the actual kilowatt hours generated by, or purchased from, qualified renewable energy based on the renewable energy input at a facility.

(ii) = 0.004 lbs. per kilowatt hour.

(e) *Certification by certifying official.* Certification of all application requirements, including Supplement A, shall be made by a certifying official of the applicant upon such official's verification of all information and documentation submitted.

(f) *Certification of the accuracy of the application and compliance with the Act and the regulations.* Applicants subject to the ratemaking jurisdiction of a State regulatory authority shall include a certification by such authority that it has reviewed the application and supplement A, including supporting documentation, and finds them to be accurate and complete.

(g) *Time period to apply.* Beginning no earlier than January 1, 1993, applicants may apply simultaneously or separately to:

(1) The Administrator for allowances from the Reserve for emissions avoided in a previous year or years by use of qualified conservation measures or qualified renewable energy generation that were operational beginning in the period of applicability; and

(2) The Secretary of Energy for the Secretary's certification of net income neutrality where the application is based on the use of qualified conservation measures. Applications will be received by the Administrator and the Secretary of Energy until January 2, 2010, pursuant to § 73.80(c).

(h) *Submittal location.* Completed applications, not including supplement A, shall be submitted to:

U.S. Environmental Protection Agency, Acid Rain Division (ANR–445), 401 M Street, SW., Washington, DC 20460, Attn. Conservation and Renewable Energy Reserve.

Supplement A shall be submitted to:

U.S. Department of Energy, Office of the Secretary, 1000 Independence Avenue, SW., Washington, DC 20585, Attn. Net Income Neutrality Certification.

§ 73.83 Secretary of Energy's action on supplement A of the application.

(a) *First come, first served.* The Secretary of Energy will process and certify applications according to the order, by date and time, in which they are received from either the applicant or the Administrator, in the case of an application submitted to the Administrator and then forwarded to the Secretary. If an application that includes supplement A is submitted to the Administrator, supplement A will be forwarded by the Administrator to the Department of Energy (DOE) within 5 business days of receipt.

(b) *Deficient applications.* If the Secretary of Energy determines that supplement A is deficient, the Secretary will notify the applicant and the Administrator in writing of the deficiency. The applicant may then supply additional information or a new revised application as necessary for the Secretary to make a determination that the applicant meets the requirements of § 73.82(a)(9). Additional information or revised applications will be processed according to the date and time of receipt of such information or revisions.

(c) *Notification of approval.* The Secretary of Energy will review the application to determine whether it meets the requirements of § 73.82(a)(9)(i) and will certify this finding in writing to the applicant and to the Administrator within 60 calendar days of receipt of supplement A or a revised application.

§ 73.84 Administrator's action on applications.

(a) *First come, first served.* The Administrator will process and approve applications in whole or in part in order of date and time of receipt, provided that the Administrator shall not allocate more than a total of 30,000 allowances in connection with applications based on any one of the four categories of qualified renewable energy generation enumerated in § 73.81(c)(2) and appendix B(3.1–3.4).

(b) *Deficient applications.* The Administrator will return applications that fail to meet the requirements set forth in § 73.82. Revised applications will be processed according to the date and time of receipt of such revised applications.

(c) *Notification of approval.* Complete and correct applications will be conditionally approved (pending certification from the Department of Energy) within 90 calendar days of receipt. Allowances from the Reserve will be designated for such applications depending on the availability of allowances in the Reserve. Final approval will be granted upon notification of certification by the Secretary of Energy pursuant to § 73.83. The Administrator will notify applicants of final approval in writing.

(d) *Transfer of allowances.* Upon final approval, the Administrator will transfer allowances from the Reserve for each approved application into a single designated account in the Allowance Tracking System. If the applicant does not have an account in the Allowance Tracking System, or wishes to open a new account for the allowances from the Reserve, a completed New Account/ New Authorized Account Representative Form must accompany the Application for Conservation and Renewable Energy Reserve.

(e) *Partial fulfillment of requests.* (1) In the event that the allowances available in the Reserve are less than the number that would otherwise be issued to an approved applicant, the applicant will receive the number of allowances remaining in the Reserve.

(2) In the event that a subaccount is established, pursuant to § 73.85(a), and the applicant is making a request for allowances not included in the subaccount, the allocation for the approved applicant will be made from any allowances remaining in the Reserve.

(f) *Oversubscription of the Reserve.* (1) If applications are received by the Administrator after all allowances from the Reserve have been allocated, the Administrator will so notify the applicant within 5 business days after receipt of the application.

(2) In the event that applications meeting the requirements pursuant to § 73.82 are received by the Administrator prior to February 1, 1998, and

(i) All remaining allowances in the Reserve have been placed in a subaccount pursuant to § 73.85(b); and

(ii) The applicant is not eligible for an allocation of allowances from the subaccount, the application will be placed on a waiting list in order of receipt.

(3) The Administrator will notify the certifying official of such action within 5 business days after receipt of the application. If any allowances are returned to the Reserve after February 1, 1998 pursuant to § 73.85(c), the Administrator will review the wait-listed applications in order of receipt and allocate any remaining allowances to the approved applicants until no more allowances remain in the Reserve.

§ 73.85 Administrator review of the Reserve program.

(a) *Administrator review of the Reserve and creation of a subaccount.* In the event that an allocation of allowances from the Reserve pursuant to a pending application would bring the total number of allowances allocated to a number greater than 240,000, the Administrator will review the distribution of all allowances allocated.

(1) If at least 60,000 allowances have been awarded for each of:

(i) Qualified energy conservation measures; and

(ii) Qualified renewable energy generation, distribution of allowances will continue pursuant to § 73.82, until no more allowances remain in the Reserve.

(2) If fewer than 60,000 allowances have been allocated for either qualified energy conservation measures or qualified renewable energy generation, the Administrator will establish a subaccount for the allocation of allowances for applications based on the category for which fewer than 60,000 allowances have been allocated. The subaccount will contain allowances equal to 60,000 less the number of allowances previously allocated for such category.

(b) *Allocation of allowances from the subaccount.* The Administrator will allocate allowances from the subaccount to qualified applicants on a first come, first served basis, pursuant to

§ 73.84(a), until the subaccount is depleted or closed pursuant to paragraph (c) of this section.

(c) *Closure of the subaccount.* Unless all allowances in the subaccount are allocated earlier, the Administrator will terminate the subaccount not later than February 1, 1998 and return any allowances remaining in the subaccount to the Reserve. After applications subject to § 73.84(f)(2) are approved, the Administrator will allocate any remaining allowances to any eligible applicant under this Subpart on a first-come, first-served basis.

§ 73.86 State regulatory autonomy.

Nothing in this Subpart shall preclude a state or state regulatory authority from providing additional incentives to utilities to encourage investment in any conservation measures or renewable energy generation.

Appendix A to Part 73—Allowance System Forms

Instructions for Completing the Allowance Tracking System New Account/New Authorized Account Representative Form

General Information

This form must be submitted to establish a new non-unit account in EPA's allowance tracking system. Completed applications should be returned to: U.S.E.P.A., Acid Rain Division (ANR-445), 401 M Street, SW, Washington, DC, 20460, Attn: Allowance Tracking System Accounts.

Paperwork Reduction Act: The public reporting burden for this collection of information is estimated to average 30 hours per response including time for reviewing instructions, gathering and maintaining the data needed, and completing and reviewing the collection of information.

Send comments regarding this burden estimate or any other aspects of this collection of information including suggestions for reducing this burden to Chief, Information Policy Branch (PM-223), U.S.E.P.A. 401 M Street, SW, Washington, DC, 20460, Attn: Acid Rain Burden; and to The Office of Information and Regulatory Affairs, Office of Management and Budget, Paperwork Reduction Project, Washington, DC 20603.

Note: Please type or print legibly in ink.

A. Authorized Account Representative Information

Authorized Account Representative: Enter the name of the officially authorized account representative (a natural person who may trade, transfer, and otherwise dispose of allowances held in an account in the allowance tracking system, including, but not limited to, the designated representative of owners and operators of an affected unit).

Address: Provide the complete address, including zip code, of the authorized account representative. All mailings will be sent to this address.

Telephone Number: Indicate the authorized account representative's daytime area code and phone number.

Telefacsimile Number: Enter the authorized account representative's telefacsimile number, if applicable.

Allowance Tracking System Number: If using this form to change the authorized account representative for an established allowance tracking system account provide the account number.

Type of Organization: Indicate the primary business of the individual, company, or organization that the authorized account representative represents.

B. Ownership Interest in Allowances

Names and Addresses of Owners: Indicate the names and addresses of all persons with an ownership interest with respect to allowances held in the non-unit account. If the authorized account representative is the only person with an ownership interest in the allowances go to section C.

C. Agreement of Representation

This section lists the requisite elements for a binding agreement between the authorized account representative and persons with ownership interest in the allowances. EPA will not review the agreement, nor will it become a party to any disputes regarding the agreement.

D. Certification

Sign and date the form. The signature provided should be that of the authorized account representative identified in section A.

BILLING CODE 6560-50-M

Form Approved. OMB Number 2060-xxxx. Approval Expires xxxx

EPA

United States Environmental Protection Agency

Washington, DC 20460

Allowance Tracking System New Account/ New Authorized Account Representative Form

A. Account Information

Name and Address of New Authorized Account Representative	Telephone Number
	Telefascimile Number
	Allowance Tracking System Number*

Type of Organization *(Please check all that apply)*

_____Utility Generator of Electricity

_____Regulated, investor owned electric utility

_____Regulated, policy owned electric utility

_____Non-regulated, investor owned electric utility

_____Non-utility Generator of Electricity

_____Qualifying cogenerator as defined by the Public Regulatory Policy Act of 1978 (PURPA)

_____Other Independent Power Producer (IPP)

_____Self generator of electricity

_____Owner or operator of an industrial facility producing steam

_____Owner or operator of a process source as defined by the Clean Air Act Amendments of 1990

_____Fuel Company

_____Coal

_____Other *(please explain)*_____

_____Integrated *(produce and sell)*

_____Fuel Broker

_____Coal

_____Other *(please explain)*_____

_____Railroad transporter of coal

_____Pollution control company

_____Public interest group

_____Consumer

_____Environmental

_____Broker/marketer of allowances

_____Other *(please explain)*_____

B. Ownership Interest In Allowances

Name and Address of Interested Person

EPA Form 7600-2 (6-91)

*Complete only if using this form to change the authorized account representative for this account number.

Name and Address of Interested Person
Name and Address of Interested Person
Name and Address of Interested Person
Name and Address of Interested Person

C. Agreement of Representation

The authorized account representative for the allowance tracking system account was selected under the terms of an agreement that is binding on all persons who have an ownership interest with respect to the allowances held in the allowance tracking system account.

The authorized account representative has all necessary authority to carry out the duties and responsibilities that are assigned to the authorized account representative under 40 CFC Part 73.

The authorized account representative will abide by the fiduciary responsibilities assigned pursuant to the binding agreement..

D. Certification

I certify under penalty of law that I personally have examined and am familiar with the information submitted in this document. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

Name of Authorized Account Representative (Please Print)	
Signature	*Date*

FOR EPA USE ONLY	**Control #**
	Time/Date

BILLING CODE 6560-50-C

Instructions for Completing the SO_2 Allowance Deduction Form

General Information

Note: Please type or print in ink.

EPA established an Allowance Tracking System to record the allocation, transfer, deduction of sulfur dioxide allowances. An Allowance Tracking System account was established for each existing unit that is, or shall become an affected unit, and will be established for other allowance holders who submit the New Account/New Authorized Account Representative Form. Each Allowance Tracking System account is identified by a unique account number. Each account consists of two types of subaccounts: one containing allowances that may be used for compliance with a unit's emissions limitation requirements in the current calendar year; and the other type containing allowances that may be used for compliance in specified future calendar years. There will be 30 of the latter type covering the 30 years after the current year.

Each allowance will be assigned a unique identification number including; (1) the unique identification of the allowance, and (2) the calendar year in which the allowance may first be used for compliance purposes.

No allowance may be used for compliance purposes unless it is properly recorded or an Allowance Transfer Form has been properly submitted for recordation in the unit's compliance subaccount on or before the "allowance transfer deadline", which is January 30 of the calendar year following the year in which the emissions took place.

Following the recordation of transfers properly submitted for recordation in the compliance subaccount, EPA will deduct from each affected unit's compliance subaccount, allowances equal to the sum of:

(a) The unit's reported sulfur dioxide emissions tonnage during the preceding calendar year; and

(b) Sulfur dioxide emissions tonnage during the preceding year resulting from any compensating generation.

EPA will continue to deduct allowances until either the number of allowances deducted equals the sum of a) and b) above or until no more allowances remain in the subaccount.

By no later than the "allowance transfer deadline", the authorized account representative for the compliance subaccount may identify by serial number the allowances to be deducted from the compliance subaccount for the purposes of compliance with the unit's emissions limitation requirements.

Allowances used for compliance will be deducted from the affected unit's compliance subaccount following the "allowance transfer deadline".

Completed Allowance Deduction Forms should be mailed to the following address: U.S.E.P.A., Acid Rain Division (ANR-445), 401 M Street, SW, Washington, DC, 20460, Attn: Allowance Tracking System.

A copy of the Allowance Deduction Form should be maintained in case of account error or dispute. In case of error, the authorized account representative may notify EPA in writing at the above address.

For more information on the allocation, transfer and use of allowances, see 40 CFR 73.10–55.

Paperwork Reduction Act: The public reporting burden for this collection of information is estimated to average 1 hour per response including time for reviewing instructions, gathering and maintaining the data needed, and completing the collection of information.

Send comments regarding this burden estimate or any other aspect of this collection of information including suggestions for reducing this burden to Chief, Information Policy Branch (PM-223), U.S.E.P.A. 401 M Street, SW, Washington, DC, 20460, Attn: Acid Rain Burden; and to The Office of Information and Regulatory Affairs, Office of Management and Budget, Paperwork Reduction Project, Washington, DC 20603.

A. Serial Numbers of Allowances to be Deducted

List the serial number(s) of the allowance(s) to be deducted. Each allowance serial number consists of: (1) the unique identification of the allowance, and (2) the calendar year in which the allowance may first be used for compliance purposes.

1. Year: Indicate the year in which the allowance(s) may first be used for compliance purposes (the first 2 digits of the allowance serial number(s)).

2. Start Number: Provide the unique identification number of the allowance to be deducted (last 7 digits of the allowance serial number). If you are deducting allowances with consecutive numbers, provide the unique identification number of the first allowance in the series.

3. Finish Number: If you are deducting allowances with consecutive numbers, provide the unique identification number of the last allowance in the series (last 7 digits of the allowance serial number). If you are deducting a single allowance, enter N/A or the same number entered in Block 3.

B. Account Information

1. Allowance Tracking System Account Number: Enter the Allowance Tracking System account number for the unit account you wish to deduct allowances from.

2. Authorized Account Representative: Indicate the name of the person designated as the authorized account representative (or alternate authorized account representative if acting on behalf of the authorized account representative) for the Allowance Tracking System account.

3. Telephone Number: Indicate the daytime area code and telephone number of the authorized account representative.

4. Telefacsimile Number: Indicate the daytime area code and telefacsimile number of the authorized account representative (if available).

5. Signature: The form must be signed by the authorized account representative (or alternate authorized account representative if acting on behalf of the authorized account representative).

6. Date: Indicate the date on which the form was signed by the authorized account representative.

You must complete a separate attachment A for each nonconsecutively numbered allowance or series of allowances you wish to deduct.

BILLING CODE 6560-50-M

OMB No. 2060-XXXX
Expires

SO2 ALLOWANCE DEDUCTION FORM

A. SERIAL NUMBERS OF ALLOWANCES TO BE DEDUCTED

List the serial numbers of allowances to be deducted on line 1 below (if numbered consecutively).

Are there attachments that list additional allowance deductions? ___ Yes ___ No
(A separate Attachment A must be completed for each non-consecutively numbered allowance or series of allowances to be deducted).

Number of Attachments that follow: ____________.

1. Year	2. Start Number	3. Finish Number
________	______________	______________

B. ACCOUNT INFORMATION

1. Allowance Tracking System Account Number ______________
2. Authorized Account Representative ______________
3. Telephone Number ______________
4. Telefacsimile Number (if available) ______________

CERTIFICATION

I certify that all information provided is true, correct and complete. I hereby certify that I am authorized by all persons with ownership interests in the allowances that are subject to this deduction to act with regard to such allowances. I am aware that there are significant penalties for submitting false or incomplete information including possibility of fine or imprisonment.

5. Authorized Account Representative Signature ______________
6. Date ______________

For Official Use Only

BILLING CODE 6560-50-C

Attachment A

SO_2 Allowance Deduction Form

Note: Please type or print in ink.

Attachment A is used to indicate the serial number(s) of the allowance(s) to be deducted. Each allowance serial number consists of three parts: (1) the unique identification of the allowance; (2) the calendar year in which the allowance may first be used for compliance purposes; and (3) the account in which the allowance is initially allocated.

You must complete a separate attachment A for each nonconsecutively numbered allowance or series of allowances you wish to deduct.

A. Allowance Tracking System Account Number

Enter the Allowance Tracking System account number for the unit account you wish to deduct allowances from.

B. Serial Number(s) of Allowance(s) To Be Deducted

1. Year: Indicate the year in which the allowance(s) may first be used for compliance purposes (the first 2 digits of the allowance serial number(s)).

2. Original Account Identification: Indicate the identification number of the account to which the allowance was originally allocated (the next 12 digits of the allowance serial number(s)).

3. Start Number: Provide the unique identification number of the allowance to be deducted (last 6 digits of the allowance serial number). If you are deducting allowances with consecutive numbers, provide the unique identification number of the first allowance in the series.

4. Finish Number: If you are deducting allowances with consecutive numbers, provide the unique identification number of the last allowance in the series (last 6 digits of the allowance serial number). If you are deducting a single allowance, enter N/A or the same number entered in Block 3.

A. Allowance Tracking System Account Number ______

B. Serial Numbers of Allowances to be Deducted ______

List the serial numbers of allowances to be deducted on line 1 below (if numbered consecutively).

A separate attachment A must be completed for each non-consecutively numbered allowance or series of allowances to be deducted.

1. Year ______
3. Start Number ______
4. Finish Number ______

Instructions for Completing the SO_2 Allowance Transfer Form

General Information

Note: Please type or print in ink.

EPA established an allowance tracking system to record the allocation and transfer of sulfur dioxide allowances. An Allowance Tracking System account was established for each existing unit that is, or shall become an affected unit, and will be established for other allowance holders who submit the New Account/New Authorized Account Representative Form. Each Allowance Tracking System account is identified by a unique account number. Each account consists of two types of subaccounts: one containing allowances that may be used for compliance with a unit's emissions limitation requirements in the current calendar year; and the other type containing allowances that may be used for compliance in specified future calendar years. There are 30 of the latter type covering the 30 years after the current year.

Each allowance is assigned a unique identification number including: (1) the unique identification of the allowance, and (2) the calendar year in which the allowance may first be used for compliance purposes.

Transfers of sulfur dioxide allowances must be recorded in the Allowance Tracking System if the transfer is to be reflected in the transferror and transferee accounts. Unless an allowance is recorded in a unit's account, it cannot be used to offset the unit's emissions. Completed Allowance Transfer Forms should be mailed to the following address: U.S.E.P.A., Acid Rain Division (ANR–445), 401 M Street, SW., Washington, DC, 20406, Attn: Allowance Tracking System.

Upon receipt of an Allowance Transfer Form, EPA will deduct the allowances from the transferror account and add them to the transferee account provided that:

(a) The Allowance Transfer Form is complete, and includes the certifying signatures of the authorized account representatives of both parties and the serial numbers of the allowances to be transferred;

(b) The allowances are in the transferror account; and

(c) The allowances have not been allocated for purposes of authorizing an extension of the transferror unit's compliance deadline in connection with the installation of repowering technology.

In addition, if the transferror unit has had excess emissions in the year preceding the transfer and EPA has not yet deducted allowances to offset the excess emissions, the number of allowances that can be transferred will be limited.

If an allowance transfer does not meet the requirements stated above, EPA will not record the transfer and will inform the affected authorized account representatives of the reasons that transfer was not recorded.

Upon recording an allowance transfer, EPA will notify the authorized account representatives of the transferror and transferee that the transfer has been recorded.

No allowance may be used for compliance purposes unless it is properly recorded, or a transfer has been properly submitted for recordation in, the unit's compliance subaccount before the "allowance transfer deadline", which is January 30 of the calendar year following the year in which the emissions took place.

Allowances used for compliance will be deducted from the affected unit's compliance subaccount following the "allowance transfer deadline".

A copy of the Allowance Transfer Form or other documentation verifying that a transfer has taken place should be maintained by one or both parties in case of account error or dispute. In case of error, the authorized account representative may notify EPA in writing at the above address.

For more information on the allocation, transfer and use of allowances, see 40 CFR 73.10–55.

Paperwork Reduction Act: The public reporting burden for this collection of information is estimated to average 1 hour per response including time for reviewing instructions, gathering and maintaining the data needed, and completing the collection of information.

Send comments regarding this burden estimate or any other aspect of this collection of information including suggestions for reducing this burden to Chief, Iinformation Policy Branch (PM–223), U.S. EPA, 401 M Street, SW., Washington, DC 20460 Attn: Acid Rain Burden; and to The Office of Information and Regulatory Affairs, Office of Management and Budget, Paperwork Reduction Project, Washington, DC 20603.

A. Serial Numbers of Allowances to be Transferred

Attachment A, indicating the serial numbers of allowances to be transferred, must be submitted with this form.

B. Transferror Information (Seller)

1. Allowance Tracking System Account Number: Enter the transferror's Allowance Tracking System account number. The transferror must have a valid account number to transfer allowances in the Allowance Tracking System.

2. Authorized Account Representative: Indicate the name of the person designated as the transferror's authorized account representative (or alternate authorized account representative if acting on behalf of the authorized account representative).

3. Telephone Number: Indicate the daytime area code and telephone number of the transferror.

4. Telefacsimile Number: Indicate the daytime area code and telefacsimile number of the transferror (if available).

5. Signature: The form must be signed by the authorized account representative (or alternate authorized account representative if acting on behalf of the authorized account representative).

6. Date: Indicate the date on which the form was signed by the authorized account representative.

C. Transferee Information (Purchaser)

1. Allowance Tracking System Account Number: Enter the transferee's Allowance Tracking System account number. If an account has not been established for the transferee, a completed New Account/New Authorized Account Representative Form must accompany the Allowance Transfer Form. If a completed New Account/New Authorized Account Representative Form is provided, the transferee may omit question 1 in section C of the Allowance Transfer Form. However, the transferee must be sure to complete questions 2 through 6 on the Allowance Transfer Form. The New Account/New Authorized Account Representative Form may be obtained by contacting EPA at the address provided on page 1 of these instructions.

2. Authorized Account Representative: Indicate the name of the person designated as the transferee's authorized account representative (or alternate authorized account representative if acting on behalf of the authorized account representative).

3. Telephone Number: Indicate the daytime area code and telephone number of the transferee.

4. Telefacsimile Number: Indicate the daytime area code and telefacsimile number of the transferee (if available).

5. Signature: The form must be signed by the authorized account representative (or alternate authorized account representative if acting on behalf of the authorized account representative).

6. Date: Indicate the date on which the form was signed by the account representative.

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OMB No. 2060-XXXX
Expires

SO2 ALLOWANCE TRANSFER FORM

A. SERIAL NUMBER(S) OF ALLOWANCE(S) TO BE TRANSFERRED

Attachment A, indicating the serial numbers of allowances to be transferred, must be submitted with this form.

B. TRANSFERROR INFORMATION (SELLER)

1. Allowance Tracking System Account Number ____________
2. Authorized Account Representative ____________
3. Telephone Number ____________
4. Telefacsimile Number (if available) ____________

CERTIFICATION

I submit this form pursuant to EPA's regulations governing the transfer of allowances as set forth in 40 CFR 73. I certify that all information provided is true, correct and complete. I hereby certify that I am authorized by all persons with ownership interests in the allowances that are subject to this transfer to act with regard to such allowances. I acknowledge and certify no action that EPA may take with respect to this transfer of allowances nullifies an affected unit's obligation to comply with its annual emissions limitation requirements. I am aware that there are significant penalties for submitting false or incomplete information including possibility of fine or imprisonment.

5. Authorized Account Representative Signature ____________
6. Date ____________

C. TRANSFEREE INFORMATION (PURCHASER)

If you do not have an Allowance Tracking System Account, you must leave item 1 of this section blank, and submit a completed New Account/New Authorized Account Representative Form with this document.

1. Allowance Tracking System Account Number ____________
2. Authorized Account Representative ____________
3. Telephone Number ____________
4. Telefacsimile Number (if available) ____________

CERTIFICATION

I submit this form pursuant to EPA's regulations governing the transfer of allowances as set forth in 40 CFR 73. I certify that all information provided is true, correct and complete. I hereby certify that I am authorized by all persons with ownership interests in the allowances that are subject to this transfer to act with regard to such allowances. I acknowledge and certify no action that EPA may take with respect to this transfer of allowances nullifies an affected unit's obligation to comply with its annual emissions limitation requirements. I am aware that there are significant penalties for submitting false or incomplete information including possibility of fine or imprisonment.

5. Authorized Account Representative Signature ____________
6. Date ____________

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BILLING CODE 6560-50-C

Attachment A

SO_2 Allowance Transfer Form

Note: Please type or print in ink.

Attachment A is to be used to indicate the serial number(s) of the allowance(s) to be transferred. Each allowance serial number consists of: (1) the unique identification of the allowance, and (2) the calendar year in which the allowance may first be used for compliance purposes.

A. Serial Number(s) of Allowance(s) to be Transferred

Check the box if you wish to transfer these allowances for every year in perpetuity, in which case no finish number is needed. If you check this box, EPA will transfer these allowances for every year unless another allowance transfer form is received with other instructions.

1. Year: Indicate the year in which the allowance(s) may first be used for compliance purposes (the first 2 digits of the allowance serial number(s)).

2. Start Number: Provide the unique identification number of the allowance to be transferred (last 7 digits of the allowance serial number). If you are transferring allowances with consecutive numbers, provide the unique identification number of the first allowance in the series.

3. Finish Number: If you are transferring allowances with consecutive numbers, provide the unique identification number of the last allowance in the series (last 7 digits of the allowance serial number). If you are transferring a single allowance, enter N/A or the same number entered in Block 3.

B. Account Information

1. Transferror Allowance Tracking System Account Number: Enter the transferror's Allowance Tracking System account number.

2. Transferee Allowance Tracking System Account Number: Enter the transferee's Allowance Tracking System account number. If the transferee does not have an account number, leave item 2 blank, and attach a New Account/New Authorized Account Representative Form.

You must complete a separate Attachment A for each non-consecutively numbered allowance or series of allowances you wish to transfer.

A. Serial Number(s) of Allowance(s) to be Transferred

Number of Attachment A's: __________

Check here if you wish to transfer these allowances for every year in perpetuity. ______

1. *Year* __________
2. *Start Number* __________
3. *Finish Number* __________

B. Account Information

1. Transferror Allowance Tracking System Account Number __________
2. Transferee Allowance Tracking System Account Number __________

Application for Energy Conservation and Renewable Energy Reserve Allowances

(Not Including Supplement A)

Please read the following sections carefully before completing this application.

Who Qualifies for Allowances From the Energy, Conservation and Renewable Energy Reserve

Section 404(g) of the Clean Air Act Amendments of 1990 (CAAA) requires EPA to establish a Conservation and Renewable Energy Reserve that sets aside 300,000 sulfur dioxide allowances for allocation to qualified utilities. Utilities applying for these allowances must meet the following requirements:

(A) Applicants must be electric utilities that own or operate, in whole or in part, an "affected unit," pursuant to the guidelines set forth under "life-of-the-unit," firm power contractual arrangements as defined in CAA section 402(27). "Affected unit" is defined in CAAA section 402(2) as a unit that is subject to emission reduction requirements or limitations under CAAA title IV.

(B) Applicants must have implemented one or more "qualified energy conservation measures" or have operational "qualified renewable energy generation" sources, or both, after January 1, 1992, and before December 31, 2000, or the date on which the relevant unit becomes an affected unit under title IV. Allowances from the Reserve will be allocated based on emissions avoided from energy conservation or renewable energy generation.

(C) The conservation or renewable energy generation options implemented must be consistent with the applicant's least cost plan; and

(D) For utilities whose rates are regulated by a state regulatory authority, the state regulatory authority with jurisdiction over the electric rates of the applicant must have established rates and charges which guarantee net income neutrality. Such net income neutrality must be certified by the Secretary of the Department of Energy.

A utility that does not meet the above requirements is not eligible to apply for allowances in the Energy Conservation and Renewable Energy Reserve. The following definitions are provided to further clarify the above requirements: least cost plans, qualified energy conservation measures, qualified renewable energy generation, and net income neutrality.

Least Cost Plans

For purpose of the allowance reserve, "least cost plan" means a least cost energy conservation and electric power planning methodology, employed by an electric utility that evaluates the full range of existing and incremental resources in order to meet expected future demand at lowest system cost. These resources include, but are not limited to, new power supplies, energy conservation and load management, and renewable resources. The plan must take into account necessary features for system operation such as diversity, reliability, dispatchability, and other factors of risk and treat demand-side and supply-side resources on a consistent and integrated basis. In addition, the least cost plan may take into account other factors, including the social and environmental costs and benefits of resource investments. The least cost plan must meet the following requirements:

(1) Involve a planning process that provides an opportunity for public notice and comment;

(2) Be submitted to the State regulatory authority for review on a regular basis or upon a utility's proposal to undertake supply- or demand-side activities;

(3) Be approved or filed with the regulatory authority in the State in which the qualifying conservation or renewable energy development takes place. Electric utilities not subject to the jurisdiction of a state regulatory authority must have such a plan or filing approved by the entity with ratemaking authority for such utility in the state in which the qualifying conservation or renewable energy development takes place; or in the event that there is no such authority, by EPA; and

(4) Upon approval, be implemented to the maximum extent practicable.

"Qualified" Energy Conservation Measure and Renewable Energy Generation

For purposes of this application, EPA defines "qualified energy conservation measures" and "qualified renewable energy generation" as follows:

A "qualified energy conservation measure" is a material or device installed by an electric utility in the home or facility of a customer to whom the electric utility provides electricity that:

(a) Increases the efficiency of the use of electricity provided by the electric utility to the customer, thereby reducing electricity consumption compared to what it otherwise would have been as measured in accordance with applicable state regulations or with the EPA Conservation Verification Protocol;

(b) Is consistent with a least cost plan;

(c) Does not increase the use by the customer of any fuel other than qualified renewable energy, industrial waste heat, or industrial waste gases;

(d) Is paid for in whole or in part directly by the electric utility;

(e) Does not result in any net increase in sulfur dioxide emissions from any affected unit owned or operated by the electric utility; and

(f) Appears on the list of measures included as an appendix to this application, or which is a measure approved by the State regulatory authority which regulates the electric utility or, if the utility is not regulated by a State authority, the EPA Administrator.

Programs that are exclusively informational in nature, or load management (unless Kwh savings due to load shifting can be demonstrated by the electric utility) are not qualified energy conservation measures for purposes of the Reserve.

"Qualified renewable energy generation" is defined as electricity generation derived from biomass, solar, geothermal, or wind resources, whose use does not provide a net increase in sulfur dioxide emissions; as defined below:

(a) Biomass resources means energy-producing materials for biological sources, including wood, plant residues, biological wastes, landfill gas, energy crops, and eligible components of municipal solid waste.

(b) Solar resources means solar thermal systems and the non-fossil fuel portion of solar thermal hybrid systems; and grid and non-grid connected photovoltaic systems including photovoltaic systems added for voltage or capacity augmentation of a distribution grid;

(c) Geothermal resources means hydrothermal or geopressurized resources used for dry steam, flash steam, or binary cycle generation of electricity; and

(d) Wind resources means grid and non-grid connected wind farms and individual wind-driven electrical generating turbines.

A list of qualified renewable energy generation sources is provided in appendix B of these instructions. Programs that reduce electricity demand, or that appear on the list of qualified energy conservation measures provided in appendix A are not considered renewable energy generation for purposes of the Reserve.

Net Income Neutrality

For purposes of the reserve, net income neutrality means, in the case of energy conservation measures undertaken by an electric utility whose rates are regulated by a State regulatory authority, rates and charges established by the State regulatory authority that ensure that the net income earned by the utility on the book value of its State-jurisdictional equity investment will be no lower as a consequence of its expenditures on qualified cost-effective energy conservation measures and any associated lost sales than it would have been had the utility not made such expenditures. EPA will forward applications to the Secretary of Energy to certify that the State regulatory authority with jurisdiction over the electric rates of the applicant that it has established rates and charges that guarantee that the utility's net income is compensated in full (considering factors such as risk) for lost sales attributable to the utility's conservation program.

Instructions for the Application for Energy Conservation and Renewable Energy Reserve Allowances

I. Application Information

This application must be submitted to obtain allowances from the Conservation and Renewable Energy Reserve. Completed applications should be returned to:
U.S.E.P.A., Acid Rain Division (ANR–445), 401 M Street, SW., Washington, DC 20460, Attn: Conservation and Renewable Energy Reserve.

Paperwork Reduction Act: The public reporting burden for this collection of information is estimated to average 80 hours per response including time for reviewing instructions, gathering and maintaining the data needed, and completing and reviewing the collection of information.

Send comments regarding this burden estimate or any other aspects of this collection of information including suggestions for reducing this burden to Chief, Information Policy Branch (PM–223), U.S.E.P.A., 401 M Street, SW., Washington, DC 20460, Attn: Acid Rain Burden; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Paperwork Reduction Project, Washington, DC 20603.

II. Instructions for Completing the Application

Note: Please type or print clearly in ink.

A. Applicant Information

Affected Unit Name: List the name of the affected unit which the applicant owns or operates, in part or in whole.

Affected Unit Allowance Tracking System Account Number: Provide the allowance tracking system account number of the affected unit.

Utility Name: Enter the name of the electric utility that owns or operates, in whole or in part, the affected unit. The applying utility may be, but is not required to be, the affected unit indicated above.

Responsible Official Name: Enter the name of the individual who will act as the responsible official for the applicant. If, for any reason, the applying utility must change the official designated as responsible official before the application is processed or approved allowances are allocated, applicants must submit the new name to EPA at the above addresses.

State-Regulated Utility: Indicate, by checking the correct box, if the applicant is rate-regulated by a State regulatory authority.

State: Indicate the state or territory in which the physical plant of the applicant is located.

Allowance Tracking System Account Number to Which Allowances are to be Allocated: Indicate the allowance tracking system account number to which the allocated allowances should be transferred. If the applicant does not have an account number, or wishes to open a new account for this purpose, leave this item blank, and submit a completed New Account Form/New Authorized Account Representative Form with this application. This form may be obtained by contacting EPA at the above address.

Authorized Account Representative Signature: If the allowances are to be transferred to an existing account, the Allowance Tracking System Account's Authorized Account Representative must sign the application here.

B. Measure Information

Type of Measure(s) Undertaken: Indicate whether an energy conservation measure or a renewable energy generation measure, or both, was implemented. If the applicant implemented both conservation and renewable energy generation measures, two separate applications must be submitted.

Measure Identification: Identify the qualified energy conservation measure(s) implemented or the renewable energy generation source used for purposes of avoiding emissions during the previous year or years. "Qualified energy conservation measures" and "qualified renewable energy generation" are defined in the introduction to this application. Appendices A and B of the instructions to this application provide a list of qualified conservation and renewable energy sources, respectively.

Energy conservation measures that are not listed in appendix A must be approved by the State regulatory authority that regulates the electric utility's electric rates, or, if the electric utility's rates are not regulated by a State authority, by the EPA Administrator, as indicated in section D. Check the box provided if the energy conservation measure(s) implemented do not appear in appendix A.

Program Cost: Indicate the dollar amount spent on the conservation measure(s) or renewable energy generation implemented. The applicant must have paid for these measures, either directly or through purchase from another person.

Time Period: Enter the year or years over which sulfur dioxide emissions were avoided using the conservation and/or renewable energy measures identified above. These savings must have occurred after January 1, 1992, and before the earlier of December 31, 2000, or the date on which the unit owned or operated by the applying facility becomes an affected unit.

Verification of Conservation Savings: For energy savings due to conservation measures:

(a) List the amount of energy savings (in kilowatt hours) per measure per year.

(b) Indicate the methodology used to calculate the savings, and the person or affiliation who performed the calculation.

Utilities rate-regulated by a State regulatory authority must use the verification methodology of their State regulatory authority. EPA reserves the right to conduct audits to ascertain that the verification is valid and correct. Utilities not rate-regulated by a State regulatory authority must use the EPA Conservation Verification Protocol which is available from EPA at the address provided above.

Verification of Renewable Energy Generation: (i) For applications submitted on the basis of qualified renewable energy generation:

(a) Identify the size of the renewable generation facility (nameplate capacity in megawatts).

(b) List the amount of yearly qualified renewable energy generation (on a Btu basis)

(c) Indicate the hours of operation during a previous calendar year or years.

(d) Attach copies of plant operation records that demonstrate the above amounts.

(ii) For applications submitted on the basis of qualified renewable energy generation using hybrid generating facilities:

(a) Indicate the size of the hybrid generating facility (nameplate capacity in megawatts).

(b) List the quantity of renewable energy input (on a Btu basis) and the percent of electric generation that can be attributed to the renewable energy input.

(c) Attach copies of plant operation records that demonstrate these amounts.

Allowances Requested: One allowance will be allocated for each ton of sulfur dioxide emissions avoided through the use of the conservation or renewable energy generation measure(s) during a calendar year or years within the period of applicability (January 1, 1992, to December 31, 2000 or the date on which the relevant unit owned or operated by the electric utility becomes an affected unit). These savings are calculated as follows:

(i) For savings from qualified energy conservation measures, the avoided emission tonnage is equal to the product of:

$$\frac{(A) \times (B)}{2000 \text{ lbs.}}$$

where (A) = the kilowatt hours that were not, but would otherwise have been supplied by the utility during such year(s) in absence of the qualified energy conservation measures; and (B) = 0.004 lbs. per kilowatt hour. The equation should be rounded to the nearest ton.

(ii) For savings from qualified renewable energy generation, the avoided emission tonnage is equal to the product of:

$$\frac{(A) \times (B)}{2000 \text{ lbs.}}$$

where (A) = the actual kilowatt hours generated by, or purchased from, qualified renewable energy based on the renewable energy input at a facility; and (B) = 0.004 lbs. per kilowatt hour. The equation should be rounded to the nearest ton.

Allowances will not be allocated for savings to be accrued in future years.

C. Approval of Least Cost Plan

The applicant must have an approved least cost plan, as defined in the introduction to this application. For utilities rate-regulated by a State regulatory authority, plans must be approved by the State regulatory authority. For utilities not rate-regulated by State regulatory authority, plans must be approved by the entity with rate-making authority for the applicant. If the electric utility is not regulated by a State regulatory or other rate-making authority, the EPA Administrator must approve the least cost plan.

The entity approving the least cost plan must also certify that the measures implemented are consistent with the findings of the least cost plan.

Signature: The signature must be that of the reviewing official.

Date: Indicate the date on which the application was certified by the reviewing official.

D. Certification by Regulatory Authority

The application must be reviewed by the entity with ratemaking authority for the utility, or, in the case of an application submitted by a utility not rate-regulated by a State authority, EPA.

Signature: For electric utilities rate-regulated by a State regulatory authority, the signature must be that of a member of such State regulatory body. For electric utilities not rate-regulated by a State authority, the EPA Administrator will make the certification. In such a case, leave this section blank.

Date: Indicate the date on which the form was signed by the regulatory entity.

E. Demonstration and Certification of Net Income Neutrality

For State-regulated investor-owned electric utilities implementing conservation measures: To demonstrate net income neutrality, attach a copy of a State regulatory filing describing the approved ratemaking mechanisms that guarantee that the utility's net income will be at least as high upon implementation of conservation measures as it would have been otherwise.

Upon application approval, EPA will forward applications from investor-owned State-regulated utilities implementing conservation measures to the Secretary of Energy to certify that the State regulatory authority with jurisdiction over the rates of the applicant has established rates and charges that ensure net income neutrality.

Signature: The signature must be that of the Secretary of Energy or an official representative.

Date: Indicate the date on which the Secretary of Energy certifies that the application is net income neutral.

F. Certification of Responsible Official

Signature: The signature must be that of the responsible official indicated in section A above.

Date: Indicate the date on which the form was signed by the responsible official.

III. General Information

This section provides additional information on the Energy Conservation and Renewable Energy Reserve Program. For a complete description of the allowance program mandated by sections 404 and 416 of the Clean Air Act Amendments, see 40 CFR part 73.

Remittance: EPA will accept applications for allowances from the Energy Conservation and Renewable Energy Reserve beginning no earlier than January 1, 1993, and ending on January 2, 2010, or until all of the allowances in the reserve have been allocated. Applicants may apply for allowances on a yearly basis or less frequently for emissions avoided in a previous year or years from qualified energy conservation measures or qualified renewable energy generation.

Processing and Approval: Applications received by EPA will be processed and approved on a first-come, first-served basis, except that EPA will not allocate more than a total of 30,000 allowances in connection with applications based on any one of the following four categories of qualified renewable energy: (1) biomass; (2) solar; (3) geothermal; and (4) wind.

The Administrator will return applications that fail to meet the application requirements within five business days of receipt. Resubmitted applications will be processed according to the postmark on the revised application.

Within 45 days of receipt, applications that meet the application requirements will be approved, or conditionally approved pending certification of the Secretary of Energy if the applicant is a State rate-regulated utility implementing conservation measures.

Allocation of Allowances: Allowances from the Reserve will be transferred into a single Allowance Tracking System Account at the time of approval or partial approval of the application, provided that a sufficient number of allowances remain in the Reserve at that time. The allowances may be transferred into an existing account if the application is signed by the Authorized Account Representative, or, into a new account if a completed New Account/New Authorized Account Representative Form accompanies the application.

Allowances from the Reserve are spot allowances that may be used for purposes of compliance beginning in the year they are allocated.

Establishment of a Reserve subaccount: The Administrator shall review the distribution of allowances from the Reserve when 240,000 of the 300,000 allowances have been allocated. If the Administrator finds that fewer than 60,000 allowances have been allocated for each of (1) qualifying energy conservation measures or (2) qualifying renewable energy generation, a subaccount will be established for the allocation of allowances to applicants implementing such measures. The subaccount will contain allowances equal to 60,000 less the number of allowances previously allocated for such category.

Unless all of the allowances in the subaccount are allocated earlier, the Administrator will terminate the subaccount not later than February 1, 1998, and return any remaining allowances to the Reserve.

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Application for Energy Conservation and Renewable Energy Reserve Allowances

A. Applicant Information

Affected Unit Name ______

Affected Unit Allowance Tracking System Account ______

Utility Name ______

Responsible Official Name ______

Applicant is Rate-Regulated by a State Regulatory Authority (check one)

Yes ☐ No ☐

State in which Utility is Located ______

Allowance Tracking System Account to which Allowances are to be Allocated ______

Signature of Authorized Account Representative ______

B. Measure Information

Type of Measure(s) Undertaken (check one)

Conservation ☐ Renewable Energy ☐

Measure Identification ______

______

Conservation measure is not on List A ☐

Program Cost ______

Time Period (Year/s) ______

Verification of Conservation Savings

a. Kilowatt hours saved ______

b. Methodology Used ______

Verification of Renewable Energy Generation

a. Nameplate Capacity (megawatts) ______

b. Energy Generation (Btus and % of Total) ______

c. Hours operated per Year ______

d. Attach copies of plant operation records verifying these numbers.

Allowances Requested ______

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C. Approval of Least Cost Plan by Ratemaking Authority

I certify that, as an official representative of the State regulatory authority or ratemaking entity of the applicant, the following criteria have been meet:

(1) The applicant's least cost plan has been approved by the authority; and
(2) The energy conservation and/or renewable energy generation measure(s) implemented by the utility are consistent with the findings in the least cost plan.

Certifying Official Signature ______________________

Name of Regulatory Body ______________________

Notary Public Signature ______________________

Date ______________________

D. Certification

I certify, as an official representative of the rate regulatory authority of the applicant, or of the U.S.E.P.A., that:

(1) I have reviewed this application and find it to be accurate and complete; and
(2) (as applicable) I have determined, according to my best profession judgement, that the energy conservation measure(s) implemented by the applicant that are not listed in Appendix A of the instructions of this application are qualified energy conservation measure(s).

Certifying Official Signature ______________________

Name of Regulatory Body ______________________

E. Demonstration of Net Income Neutrality
(for state rate-regulated utilities only)

Applicants must attach a copy of a regulatory filing describing the approved rulemaking mechanisms that guarantee net income neutrality.

Certification of Net Income Neutrality

- I certify that the state regulatory authority with jurisdiction over the electric rates of the applicant has established rates and charges that ensure net income neutrality.

Secretary of Energy Signature ______________________

Date ______________________

F. Certification of Responsible Official

I submit this form pursuant to EPA's regulations governing the allocation of allowances in the energy conservation and renewable energy reserve. I certify that the electric utility owns or operates, in whole or in part, an affected unit, and that qualified energy conservation or renewable energy generation measure(s) were implemented consistent with the utility's approved least cost plan. I further certify that the information provided in this form is true and correct

Responsible Official Signature ______________________

Notary Public Signature ______________________

Date ______________________

BILLING CODE 6560-50-C

Appendix B to Part 73—List of Qualified Energy Conservation Measures

1. Demand-side Measures Applicable for the Conservation and Renewable Energy Reserve Program or Reduced Utilization

The following listed measures are approved as "qualified energy conservation measures" for purposes of the Conservation and Renewable Energy Reserve Program or Reduced Utilization. Measures not appearing on the list may also be approved if it is demonstrated that they meet the criteria specified in § 73.81(a) of the regulations.

1.1 Residential

1.1.1 Space Conditioning

- Electric furnace improvements (intermittent ignition, automatic vent dampers, and heating element change-outs)
- Air conditioner (central and room) upgrades/replacements
- Heat pump (ground source, solar assisted, and conventional) upgrades/replacements
- Cycling of air conditioners and heat pumps
- Natural ventilation
- Heat recovery ventilation
- Thermal energy storage
- Clock thermostats
- Setback thermostats
- Geothermal steam direct use
- Improved equipment controls
- Solar assisted space conditioning (ventilation, air-conditioning, and desiccant cooling)
- Passive solar designs
- Air conditioner and heat pump clean and tune-up
- Heat pipes
- Whole house fans
- High efficiency fans and motors
- Hydronic pump insulation
- Register relocation
- Register size and blade configuration
- Return air location
- Duct sizing
- Duct insulation
- Duct sealing
- Duct cleaning
- Shade tree planting

1.1.2 Water Heating

- Electric water heater upgrades/replacements
- Electric water heater tank wraps/blankets
- Low-flow showerheads and fittings
- Solar heating and pre-heat units
- Geothermal heating and pre-heat units
- Heat traps
- Water heater heat pumps
- Recirculation pumps
- Setback thermostats
- Water heater cycling control
- Solar heating for swimming pools
- Pipe wrap insulation

1.1.3 Lighting

- Lamp replacement
- Dimmers
- Motion detectors and occupancy sensors
- Photovoltaic lighting
- Fixture replacement
- Outdoor lighting controls

1.1.4 Building Envelope

- Attic, basement, ceiling, and wall insulation
- Passive solar building systems
- Exterior roof insulation
- Exterior wall insulation
- Exterior wall insulation bordering unheated space (e.g., a garage)
- Knee wall insulation in attic
- Floor insulation
- Perimeter insulation
- Storm windows/doors
- Caulking/weatherstripping
- Multi-glazed inserts for sliding glass doors
- Sliding door replacements
- Installation of French doors
- Hollow core door replacement
- Radiant barriers
- Window vent conversions
- Window replacement
- Window shade screens
- Low-e windows
- Window reduction
- Attic ventilation
- Whole house fan
- Passive solar design

1.1.5 Other Appliances

- Refrigerator replacements
- Freezer replacements
- Oven/range replacements
- Dishwasher replacements
- Clothes washer replacements
- Clothes dryer replacements
- Customer located power generation based on photovoltaic, solar thermal, biomass, wind or geothermal resources
- Swimming pool pump replacements
- Gasket replacements
- Maintenance/coil cleaning

1.2 Commercial

1.2.1 Heating/Ventilation/Air Conditioning (HVAC)

- Heat pump replacement
- Fan motor efficiency
- Resizing of chillers
- Heat pipe retrofits in air conditioning units
- Dehumidifiers
- Steam trap insulation
- Radiator thermostatic valves
- Variable speed drive on fan motor
- Thermal storage
- Solar assisted HVAC including ventilation, chillers, heat pumps, and desiccants
- HVAC piping insulation
- HVAC ductwork insulation
- Boiler insulation
- Automatic night setback
- Automatic economizer cooling
- Outside air control
- Hot and cold deck automatic reset
- Reheat system primary air optimization
- Process heat recovery
- Deadband thermostat
- Timeclocks on circulating pumps
- Chiller system
- Increase condensing unit efficiency
- Separate make-up air for exhaust hoods
- Variable air volume system
- Direct tower cooling (chiller strainer cycle)
- Thermal storage
- Multiple chiller control
- Radiant heating
- Evaporative roof surface cooling
- Cooling tower flow control
- Ceiling fans
- Evaporative cooling
- Direct expansion cooling system
- Heat recovery ventilation (water and air-source)
- Set-back controls for heating/cooling
- Make-up air control
- Manual fan switches
- Energy saving exhaust hood
- Night flushing
- Spot radiant heating
- Terminal regulated air volume control scheme
- Variable speed motors for HVAC system
- Waterside economizers
- Airside economizer
- Gray water systems
- Well water for cooling

1.2.2 Building envelope

- Insulation
- Wall insulation
- Floor/slab insulation
- Roof insulation
- Window and door upgrades, replacements, and films (to reduce solar heat gains)
- Passive solar design
- Earth berming
- Shading devices and tree planting
- High reflectivity roof coating
- Evaporative cooling
- Infiltration reduction
- Weatherstripping
- Caulking
- Low-e windows
- Multi-glazed windows
- Replace glazing with insulated walls
- Thermal break window frames
- Tinted glazing
- Vapor barrier
- Vestibule entry

1.2.3 Lighting

- Electronic ballast replacements
- Delamping
- Reflectors
- Occupancy sensors
- Daylighting with controls
- Photovoltaic lighting
- Efficient exterior lighting
- Manual selective switching
- Efficient exit signs
- Daylighting construction
- Cathode cutout ballasts
- High intensity discharge luminaries
- Outdoor light timeclock and photocell

1.2.4 Refrigeration

- Refrigerator replacement
- Freezer replacement
- Optimize heat gains to refrigerated space
- Optimize defrost control
- Refrigeration pressure optimization control
- High efficiency compressors
- Anti-condensate heater control
- Floating head pressure
- Hot gas defrost
- Parallel unequal compressors
- Variable speed compressors
- Water cooler controls
- Waste heat utilization
- Air doors on refrigeration equipment

1.2.5 Water Heating

- Electric water heating upgrades/replacements

- Electric water heater wraps/blankets
- Pipe insulation
- Solar heating and/or pre-heat units
- Geothermal heating and/or pre-heat units
- Circulating pump control
- Point-of-use water heater
- Heat recovery DHW system
- Chemical dishwashing system
- End-use reduction using low-flow fittings

1.2.6 Other end-uses and miscellaneous
- Energy management control systems for building operations
- Customer located power based on photovoltaic, solar thermal, biomass, wind, and geothermal resources
- Energy efficient office equipment
- Customer-owned transformer upgrades and proper sizing

1.3 Industrial

1.3.1 Motors
- Retire inefficient motors and replace with energy efficient motors, including the use of electronic adjustable speed or variable frequency drives
- Rebuild motors to operate more efficiently through greater contamination protection and improved magnetic materials
- Install self-starters
- Replace improperly sized motors

1.3.2 Lighting
- Electronic ballast replacement/improvement
- Electromagnetic ballast upgrade
- Installation of reflectors
- Substitution of lamps with built-in automatic cathode cut-out switches
- Modify ballast circuits with additional impedance devices
- Metal halide and high pressure sodium lamp retrofits
- High pressure sodium retrofits
- Daylighting with controls
- Occupancy sensors
- Delamping
- Photovoltaic lighting
- Two step and dimmable high intensity discharge ballast

1.3.3 Heating/Ventilation/Air Conditioning (HVAC)
- Heat pump replacement/upgrade
- Furnace upgrade/replacement
- Fan motor efficiency
- Resizing of chillers
- Heat pipe retrofits on air conditioners
- Variable speed drive on fan motor
- Thermal storage
- Solar assisted HVAC including ventilation, chillers, heat pumps and desiccants

1.3.4 Industrial Processes
- Upgrades in heat transfer equipment
- Insulation and burner upgrades for industrial furnaces/ovens/boilers to reduce electricity loads on motors and fans
- Insulation and redesign of piping
- Upgrades/retrofits in condenser/evaporation equipment
- Process air and water filtration for improved efficiency
- Upgrades of catalytic combustors
- Solar process heat
- Customer located power based on photovoltaic, solar thermal, biomass, wind, and geothermal resources
- Power factor controllers
- Utilization of waste by-product fuels
- Steam line and steam trap repairs/upgrades
- Compressed air system improvements/repairs
- Industrial process heat pump
- Optimization of equipment lubrication or maintenance
- Resizing of process equipment for optimal energy efficiency
- Use of unique thermodynamic power cycles

1.3.5 Building Envelope
- Insulation of ceiling, walls, and ducts
- Window and door replacement/upgrade, including thermal energy barriers
- Caulking/weatherstripping

1.3.6 Water Heating
- Electric water heater upgrades/replacements
- Electric water heater wraps/blankets
- Pipe insulation
- Low-flow showerheads and fittings
- Solar heating and pre-heat units
- Geothermal heating and pre-heat units

1.3.7 Other end-uses and miscellaneous
- Refrigeration system retrofit/replacement
- Energy management control systems and end-use metering
- Customer-owned transformer retrofits/replacements and proper sizing

1.4 Agricultural

1.4.1 Space Conditioning
- Building envelope measures
- Efficient HVAC equipment
- Heat pipe retrofit on air conditioners
- System and control measures
- Solar assisted HVAC including ventilation, chillers, heat pumps, and desiccants
- Air-source and geothermal heat pumps replacement/upgrades

1.4.2 Water heating
- Upgrades/replacements
- Water heater wraps/blankets
- Pipe insulation
- Low-flow showerheads and fittings
- Solar heating and/or pre-heat units
- Geothermal heating and/or pre-heat units

1.4.3 Lighting
- Electronic ballast replacements
- Delamping
- Reflectors
- Occupancy sensors
- Daylighting with controls
- Photovoltaic lighting
- Outdoor lighting controls

1.4.4 Pumping/Irrigation
- Pump upgrades/retrofits
- Computerized pump control systems
- Irrigation load management strategies
- Irrigation pumping plants
- Computer irrigation control
- Surge irrigation
- Computerized scheduling of irrigation
- Drip irrigation systems

1.4.5 Motors
- Retire inefficient motors and replace with energy efficient motors, including the use of electronic adjustable speed and variable frequency drives
- Rebuild motors to operate more efficiently through greater contamination protection and improved magnetic materials
- Install self-starters
- Replace improperly sized motors

1.4.6 Other end uses
- Ventilation fans
- Cooling and refrigeration system upgrades
- Grain drying using unheated air
- Grain drying using low temperature electric
- Customer-owned transformer retrofits/replacements and proper sizing
- Programmable controllers for electrical farm equipment
- Controlled livestock ventilation
- Water heating for production agriculture
- Milk cooler heat exchangers
- Direct expansion/ice bank milk cooling
- Low energy precision application systems
- Heat pump crop drying

1.5 Government Services Sector

1.5.1 Streetlighting
- Replace incandescent and mercury vapor lamps with high pressure sodium and metal halide

1.5.2 Other
- Energy efficiency improvements in motors, pumps, and controls for water supply and waste water treatment
- District heating and cooling measures derived from cogeneration that result in electricity savings

2. Supply-side Measures Applicable for Reduced Utilization

In addition to the measures specified in (a), the following supply-side measures may be approved for purposes of reduced utilization qualified energy conservation plans under § 72.43:

2.1 Generation efficiency
- Heat rate improvement programs
- Availability improvement programs
- Coal cleaning
- Turbine improvements
- Boiler improvements
- Control improvements, including artificial intelligence and expert systems
- Distributed control—local (real-time) versus central (delayed)
- Equipment monitoring
- Performance monitoring
- Preventive maintenance
- Additional or improved heat recovery
- Sliding/variable pressure operations
- Adjustable speed drives
- Improved personnel training to improve man/machine interface

2.2 Transmission and distribution efficiency
- High efficiency transformer switchouts using amorphous core and silicon steel technologies
- Low-loss windings
- Innovative cable insulation
- Reactive power dispatch optimization
- Power factor control
- Primary feeder reconfiguration
- Primary distribution voltage upgrades
- High efficiency substation transformers
- Controllable series capacitors
- Real-time distribution data acquisition analysis and control systems
- Conservation voltage regulation

3. Renewable Energy Generation Measures Applicable for the Conservation and Renewable Energy Reserve Program

The following listed sources are approved as "qualified renewable energy generation" for purposes of the Conservation and Renewable Energy Reserve Program. Sources not appearing on the list may be approved if it is demonstrated that they meet the criteria specified in § 73.81(c) of the regulations.

3.1 Biomass resources
- Combustible energy-producing materials from biological sources which include: wood, plant residues, biological wastes, landfill gas, and energy crops, and eligible components of municipal solid waste.

3.2 Solar resources
- Solar thermal systems and the non-fossil fuel portion of solar thermal hybrid systems
- Grid and non-grid connected photovoltaic systems, including systems added for voltage or capacity augmentation of a distribution grid.

3.4 Geothermal resources
- Hydrothermal or geopressurized resources used for dry steam, flash steam, or binary cycle generation of electricity.

3.5 Wind resources
- Grid-connected and non-grid-connected wind farms
- Individual wind-driven electrical generating turbines

PART 75—CONTINUOUS EMISSION MONITORING

Sec.

Authority: Secs. 412 and 821, Pub.L. 101-549, 104 Stat. 2624, 2699.

Subpart A—General

§ 75.1 Purpose.

(a) This part establishes requirements for the installation, operation, maintenance, and certification of continuous emission monitoring systems for the measurement, recording, and standardized electronic reporting of SO_2 and NO_X emissions, volumetric flow, and opacity data from Phase I and Phase II affected units under title IV of the Act. Requirements for alternative monitoring systems and for the quality assurance and quality control of continuous emission monitoring data also are established.

(b) This part also establishes requirements for the monitoring and reporting of CO_2 emissions pursuant to section 821 of the Act.

§ 75.2 Definitions.

The terms used in this part are defined in the Act or in this section as follows.

Accuracy means the closeness of the measurement made by a continuous emission monitoring system, a pollutant concentration monitor or a flow monitor to the true value of the emissions or volumetric flow. It is expressed as the difference between the measurement and a reference method value, which is assumed to be equivalent to the true value. Variation among these differences represents the variation in accuracy which could be caused by random or systematic error.

Acid Rain Program means the sulfur dioxide and nitrogen oxides air pollution control program established pursuant to title IV of the Act under 40 CFR parts 72–78.

Act means the Clean Air Act, 42 U.S.C. 7401, et seq., as amended by Public Law 101-549, November 15, 1990.

Administrator means the Administrator of the United States Environmental Protection Agency (EPA) or the Administrator's duly authorized representative.

Affected unit means a unit or source that is subject to any emission reduction requirement or limitation under the Acid Rain Program, or a unit or source that opts-in under 40 CFR part 74.

Alternative monitoring system means a system designed to provide direct or indirect determinations of mass per unit time emissions, pollutant concentrations, and/or volumetric flow data that are demonstrated to the Administrator as having the same precision, reliability, accessibility, and timeliness as the data provided by a continuous emission monitoring system.

As-fired means the taking of a fuel sample just prior to its introduction into the boiler for combustion.

Available means the continuous emission monitoring system or continuous opacity monitoring system is functional and operating within the calibration error and other applicable performance specifications.

Bias means systematic error. The result of bias is that measurements will be either consistently low or high relative to the true value.

Boiler means a fossil or other fuel-fired combustion device used to produce heat and to transfer heat to water, steam, or through another medium.

By-pass means any duct, stack, or conduit through which emissions from an affected unit may or do pass to the atmosphere, which either augments or substitutes for the principal ductwork and stack exhaust system during any portion of the unit's operation.

Calibration error means the difference between (1) the response of a gaseous monitor to a calibration gas and the known concentration of the gas, (2) the response of a flow monitor to a reference signal and the known value of the reference signal, or (3) the response of a continuous opacity monitoring system to an attenuation filter and the known value of the filter after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

Calibration gas means for the purposes of this part, a known concentration of a gas (1) that is traceable to either a standard reference material gas or a National Institute of Standards and Technology (NIST)/EPA-approved certified reference material gas or (2) that is a Protocol 1 gas. A gas that is traceable to a gas manufacturer's intermediate standard is not a calibration gas for the purposes of this part.

Centroidal area means a concentric area that is geometrically similar to the stack or duct cross section and is not greater than 1 percent of the stack or duct cross-sectional area.

Coal-fired means the combustion of fuel consisting of coal or any coal-derived fuel, alone or in combination with any other fuel, independent of the percentage of coal consumed on a Btu basis.

Commence construction means that an owner or operator has undertaken a continuous program of construction or has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction.

Commence operation means to have begun the combustion of fuel in the unit's combustion chamber.

Commence commercial operation means to have begun to generate electricity for sale, including test generation.

Common stack means the exhaust of two or more units through a single flue in a single stack.

Construction means fabrication, erection, or installation of an affected unit.

Continuous means capable of obtaining a sample at least every 15 min.

Continuous emission monitoring system means the equipment required by this part used to sample, analyze, measure, and provide, on a continuous basis, a permanent record of emissions and volumetric flow expressed in pounds per hour (lb/hr) for sulfur dioxide, in standard cubic feet per hour (scfh) for volumetric flow, and in pounds per million Btu (lb/mmBtu) of heat input for nitrogen oxides. The following systems are component parts included in a "continuous emission monitoring system": (1) Sulfur dioxide pollutant concentration monitor, (2) flow monitor, (3) nitrogen oxides pollutant concentration monitor, (4) diluent gas monitor (oxygen or carbon dioxide), and (5) data acquisition and handling system. A continuous moisture monitor may also be included.

Continuous opacity monitoring system means the equipment used to sample, measure, analyze, and provide, on a continuous basis, a permanent record of opacity or transmittance.

Data acquisition and handling system means that component of the continuous emission monitoring system designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, and other components of the continuous emission monitoring system to produce a continuous readout of the measured parameters in units required by this part.

Designated representative means a natural person authorized by the owners and operators of a source and of all affected units at the source, as evidenced by a certificate of representation submitted in accordance with 40 CFR part 72, subpart B, to represent and legally bind the owners and operators jointly and severally as a matter of Federal law in all matters relating to the Acid Rain Program. Except for § 72.20(c), the term "designated representative" shall also mean any natural person designated in accordance with 40 CFR part 72 as an alternative designated representative to act on behalf of the person authorized in accordance with the preceding sentence. Whenever the term "responsible official" is used in 40 CFR part 70 or part 71 or in a State operating permit program, it shall be deemed to refer to the "designated representative" as defined here insofar as Acid Rain Program actions, standards, requirements, or prohibitions are concerned.

Diluent gas means a major gaseous constituent in a gaseous pollutant mixture. For combustion sources, carbon dioxide and oxygen are the major diluent gases.

Dual span system means a pollutant concentration monitor, flow monitor, or opacity monitor that has two ranges of values over which measurements are made.

Equivalent diameter means a calculated value used to determine the upstream and downstream distances for locating flow or pollutant concentration monitors in ducts or stacks with rectangular cross sections. The equation in paragraph 2.1 of Method 1 in 40 CFR part 60, appendix A, is used to determine equivalent diameter.

Excess emissions of opacity means the measured opacity during any 6-minute period or other State-promulgated and approved averaging period when the applicable Federal or State opacity limit, whichever is more restrictive, is exceeded.

Existing unit means a unit (including units subject to Section 111 of the Act) that commenced commercial operation before November 15, 1990. Any unit that commenced commercial operation before November 15, 1990, and that is modified, reconstructed, or repowered after November 15, 1990, shall continue to be an existing unit. Existing units do not include simple combustion turbines or units that serve only a generator with a nameplate capacity of 25 megawatt electrical output or less.

Flow monitor means a component of the continuous emission monitoring system that measures the volumetric flow of exhaust gas from an affected unit or source.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

Gas-fired means the combustion of natural gas for 90 percent or more of the annual heat input and of fuel oil (including diesel fuel) for the remaining heat input.

Gas manufacturers intermediate standard means a compressed (cylinder) gas standard that has been assayed with direct reference to a standard reference material gas or NIST/EPA-approved certified reference material and that has been certified by, and met all other requirements of, "Revised Traceability Protocol No. 1."

Limited life means any affected unit that permanently ceases operation before January 1 of the first year for which it is required, under Title IV of the Act, to hold allowances to account for its emissions of sulfur dioxide.

New unit means a unit that commences commercial operation on or after November 15, 1990, including any such unit that serves a generator with a nameplate capacity of 25 megawatt electrical output or less or a simple combustion turbine.

Ninetieth (90th) percentile means a value that would divide an ordered set of increasing values so that at least 90 percent are less than or equal to the value and at least 10 percent are greater than or equal to the value.

NIST/EPA-approved certified reference material means a reference material one or more of whose property values are certified by a technically valid procedure, accompanied by or traceable to a certificate or other documentation that is issued by a certifying body and approved by EPA. A current list of certified reference material cylinder gases and certified reference material vendors is available from the Quality Assurance Division (MD–77), Environmental Monitoring Systems Laboratory, U.S. EPA, Research Triangle Park, NC 27711.

Oil-fired means the combustion of fuel oil (including diesel fuel) for more than 10 percent of the annual heat input and natural gas and no other fuels for the remaining heat input.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Operational period means a minimum period of time over which a measurement system is expected to operate within certain performance specifications set forth in Appendix A of this part without unscheduled maintenance, repair, or adjustment.

Out-of-control period means any period beginning with the hour that a daily calibration error or electronic drift or quality assurance audit begins that indicates that the instrument is not measuring and recording within the appropriate performance specifications

except as specifically provided in this part. The end of the period is the hour corresponding to the completion of an additional calibration error or electronic drift check or quality assurance audit following corrective action that demonstrates that the instrument is measuring and recording within the appropriate performance specifications.

Owner means any of the following persons: (1) Any holder of any portion of the legal or equitable title on an affected unit; (2) any holder of a leasehold interest in an affected unit; or (3) any purchaser of power from an affected unit under a life-of-the-unit, firm power contractual arrangement as that term is used in section 408(i) of the Act. However, unless expressly provided for in a leasehold agreement, "owner" does not include a passive lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the affected unit.

Owner or operator means any person who is an owner or who operates, controls, or supervises in any way an affected unit or an affected source of which an affected unit is a part and includes but is not limited to any holding company, operating company, utility systems, designated representative, or plant manager of an affected unit or affected source.

Path continuous emission monitoring system means a continuous emission monitoring system that measures the pollutant concentration along a path greater than 10 percent of the equivalent diameter of the stack or duct cross section.

Permitting authority means either of the following: (1) The Administrator in the case of EPA implementation of the Acid Rain Program; or (2) the State air pollution control agency, local agency, other State agency, Indian tribe, or other agency authorized by the Administrator to issue proposed Acid Rain permits under titles IV and V of the Act and 40 CFR part 70 and part 72, subpart I.

Point continuous emission monitoring system means a continuous emission monitoring system that measures the pollutant concentration either at a single point or along a path equal to or less than 10 percent of the equivalent diameter of the stack or duct cross section.

Pollutant concentration monitor means that component of the continuous emission monitoring system that measures unit exhaust gas pollutant concentration.

Precision means the closeness of a measurement to the actual measured value expressed as the uncertainty associated with repeated measurements of the same sample or of different samples from the same process (e.g., the random error associated with simultaneous measurements of a process made by more than one instrument). A measurement technique is determined to have increasing precision as the variation among the repeated measurements decreases.

Protocol 1 gas means a calibration gas mixture prepared and analyzed according to "Revised Traceability Protocol No. 1" (see "Procedure for NBS-Traceable Certification of Compressed Gas Working Standards Used for Calibration and Audit of Continuous Emission Monitors," Quality Assurance Handbook for Air Pollution Measurement Systems, Volume III, Stationary Source Specific Methods, section 3.04, EPA-600/4-77-027b, June 1987). The certified concentrations for calibration gas mixtures developed using "Revised Traceability Protocol No. 1" are traceable to a standard reference material or an NIST/EPA-approved certified reference material.

Qualifying Phase I technology means a technological system of continuous emission reduction that is demonstrated to achieve a 90-percent reduction in emissions of sulfur dioxide from the emissions that would have resulted from the combustion of fossil fuels that were not subject to treatment prior to combustion, as provided in 40 CFR 72.42.

Reference method means any method of sampling and analyzing for an air pollutant as specified in 40 CFR part 60, appendix A.

Reference value means the known concentration of a calibration gas certified to a standard reference material.

Relative accuracy means, in general, a statistic designed to provide a measure of the systematic and random errors associated with data from continuous emission monitoring systems. Specifically, *relative accuracy* is the absolute mean difference between the pollutant concentration or volumetric flow determined by the continuous pollutant or flow monitoring system and the value determined by the appropriate reference methods plus the 2.5 percent error confidence coefficient of a series of tests divided by the mean of the reference method tests.

Span means the range of values that can be measured by a continuous emission monitoring system.

Standard reference material means a reference material distributed and certified by the National Institute of Standards and Technology.

Standard absolute pressure means 29.92 in. of mercury or 760 mm of mercury.

Standard absolute temperature means 20° C, 293° K, 68° F, or 528° R.

Standard conditions means 68° F at 1 atm (29.92 in. of mercury).

State means one of the 48 contiguous States and the District of Columbia and includes all non-Federal authorities, including local agencies, interstate associations, tribal authorities, and State agencies with approved permit programs under 40 CFR part 70. The term *State* also encompasses those Native American governing bodies that the Administrator has determined, pursuant to section 301(d) of the Act, to treat as States.

Substitute data means emissions or volumetric flow data provided to assure 100 percent recording and reporting of emissions when all or part of the continuous emission monitoring system is not functional or is operating outside applicable performance specifications.

Substitution unit means an affected unit that is listed in 40 CFR part 72, appendix B, and is designated as a Phase I affected unit in a substitution plan under 40 CFR 72.41.

Uncontrolled emission rate means the maximum hourly pollutant emission rate of sulfur dioxide or nitrogen oxides emitted during the previous 365 days for an affected unit. Where no previous continuous emission monitoring data exist for sulfur dioxide, the *uncontrolled emission rate* means the maximum possible emission rate, calculated as the product of the maximum sulfur content of the fuel used and the maximum fuel feed rate of the unit at full generating capacity. Where no previous continuous emission monitoring data exist for nitrogen oxides, the *uncontrolled emission rate* is calculated based on the operating parameters of the affected unit and equations in "Compilation of Air Pollutant Emission Factors" (Volume I: Stationary Point and Area Sources, AP-42, fourth edition, September 1985, and applicable supplements).

Unit means a fossil fuel-fired combustion device.

Unit operating hours means, in reference to continuous emission monitoring system availability, the number of hours that a unit (boiler) combusts any fuel.

Utility unit means a unit owned or operated by a utility (1) that serves a generator that produces electricity for sale, or (2) that during 1985, served a generator that produced electricity for sale. Notwithstanding paragraphs (1) and (2) of this definition, a unit that was in commercial operation during 1985, but did not, during 1985, serve a generator that produced electricity for sale is not a *utility unit* for the purposes of the Acid

Rain Program. Notwithstanding paragraphs (1) and (2) of this definition, a unit that cogenerates steam and electricity is not a utility unit for the purposes of the Acid Rain Program, unless the unit is constructed for the purpose of supplying, or commences construction after November 15, 1990, and supplies, more than one-third of its potential electric output capacity and more than 25 megawatt electrical output to any utility power distribution system for sale.

§ 75.3 Units and abbreviations.

(a) The abbreviations and symbols of units of measure used in this part are defined as follows.

Btu—British thermal unit
°C—degree Celsius (centigrade)
cfm—cubic feet per minute
cm—centimeter
dcf—dry cubic feet
dscf—dry cubic feet at standard conditions
dscfh—dry cubic feet per hour at standard conditions
eq—equivalent
°F—degree Fahrenheit
fps—feet per second
gal—gallon
hr—hour
lb—pound
m—meter
mmBtu—million Btu
min—minute
mol. wt.—molecular weight
MWe—megawatt electrical
MWge—gross megawatt electrical
ppm—parts per million
°R—degree Rankine
scf—cubic feet at standard conditions
scfh—cubic feet per hour at standard conditions
sec—second
std—at standard conditions

(b) Chemical nomenclature include:

CO_2—carbon dioxide
NO_x—nitrogen oxides
O_2—oxygen
SO_2—sulfur dioxide

§ 75.4 Addresses.

(a) Except as specified in paragraph (d) of this section, all requests for certification or recertification, applications for alternative monitoring systems, notifications, electronic reports, and other communications to the Administrator required by §§ 75.18, 75.21, or § 75.23 shall be submitted to the Chief, Emissions Monitoring Section, Acid Rain Division (ANR-445), Office of Atmospheric and Indoor Air Programs, U.S. Environmental Protection Agency, 401 M Street, SW., Washington, DC 20460.

(b) Acid Rain Program plant and unit identification numbers (for the Aerometric Information Retrieval System) required by § 75.23(a) are listed in appendices A and B of 40 CFR part 72. They may also be obtained from the Chief, Allowance Tracking Section, Acid Rain Division (ANR-445), Office of Atmospheric and Indoor Air Programs, at the address given in paragraph (a) of this section.

(c) Copies of requests for initial certification or recertification of a continuous emission monitoring system required by § 75.23(c) shall be submitted to the appropriate Regional Office of the U.S. Environmental Protection Agency to the attention of the Director of the Division indicated in the following list of EPA Regional Offices. A copy of the documentation also shall be submitted to the appropriate State air pollution control agency.

Region I (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont), Director, Air Management Division, U.S. Environmental Protection Agency, John F. Kennedy Federal Building, Boston, Massachusetts 02203.
Region II (New Jersey, New York, Puerto Rico, Virgin Islands), Director, Air and Waste Management Division, U.S. Environmental Protection Agency, Federal Office Building, 26 Federal Plaza (Foley Square), New York, New York 10278.
Region III (Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia), Director, Air and Toxics Division, U.S. Environmental Protection Agency, 841 Chestnut Building, Philadelphia, Pennsylvania 19107.
Region IV (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee), Director, Air, Pesticides and Toxics Division, U.S. Environmental Protection Agency, 345 Courtland Street, NE., Atlanta, Georgia 30365.
Region V (Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin), Director, Air and Radiation Division, U.S. Environmental Protection Agency, 230 South Dearborn Street, Chicago, Illinois 60604.
Region VI (Arkansas, Louisiana, New Mexico, Oklahoma, Texas), Director, Air, Pesticides, and Toxics Division, U.S. Environmental Protection Agency, 1445 Robs Avenue, Dallas, Texas 75202.
Region VII (Iowa, Kansas, Missouri, Nebraska), Director, Air and Toxics Division, U.S. Environmental Protection Agency, 726 Minnesota Avenue, Kansas City, Missouri 66101.
Region VIII (Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming), Director, Air and Toxics Division, U.S. Environmental Protection Agency, 999 18th Street, Suite 500, Denver, Colorado 80202-2405.
Region IX (Arizona, California, Guam, Hawaii, Nevada), Director, Air and Toxics Division, U.S. Environmental Protection Agency, 75 Hawthorne Street, San Francisco, California 94103.
Region X (Alaska, Oregon, Idaho, Washington), Director, Air and Waste Management Division, U.S. Environmental Protection Agency, 1200 Sixth Avenue, Seattle, Washington 98101.

(d) The acid rain continuous emission monitoring information and opacity reports required by §§ 75.23(a) and 75.23(g) shall be submitted to the applicable permitting authority at the following address.

State of Alabama, Air Pollution Control Division, 645 S. McDonough Street, Montgomery, Alabama 36104.
State of Arizona, Department of Health Services, 1740 West Adams Street, Phoenix, AZ 85007.
State of Arkansas, Division of Air Pollution Control, Department of Pollution Control and Ecology, 8001 National Drive, P.O. Box 9583, Little Rock, Arkansas 72209.
State of California, Air Resources Board, 1102 Q Street, Sacramento, CA 95814.
State of Colorado, Department of Health, Air Pollution Control Division, 4210 East 11th Avenue, Denver, CO 80220.
State of Connecticut, Department of Environmental Protection, State Office Building, Hartford, Connecticut 06115.
State of Delaware, Delaware Department of Natural Resources and Environmental Control, 89 Kings Highway, P.O. Box 1401, Dover, Delaware 19901.
District of Columbia, Department of Consumer and Regulatory Affairs, 614 M Street, NW., Washington, DC 20001.
State of Florida, Bureau of Air Quality Management, Department of Environmental Regulation, Twin Towers Office Building, 2600 Blair Stone Road, Tallahassee, Florida 32301.
State of Georgia, Environmental Protection Division, Department of Natural Resources, 205 Butler Street, SE., East Tower, Atlanta, Georgia 30334.
State of Idaho, Department of Health and Welfare, Statehouse, Boise, Idaho 83701.
State of Illinois, Division of Air Pollution Control, 2200 Churchill Road, Springfield, Illinois 62706.
State of Indiana, Indiana Department of Environmental Management, 105 South Meridian Street, P.O. Box 6015, Indianapolis, Indiana 46206.
State of Iowa, Iowa Department of Natural Resources, Air Quality and Solid Waste Protection Bureau, Henry A. Wallace Building, 900 East Grand, Des Moines, Iowa 50319.
State of Kansas, Kansas Department of Health and Environment, Bureau of Air Quality and Waste Management, Forbes Field, Topeka, Kansas 66620.
State of Kentucky, Division of Air Pollution Control, Department for Natural Resources and Environmental Protection, U.S. 127, Frankfort, Kentucky 40601.
State of Louisiana, Program Administrator, Air Quality Division, Louisiana Department of Environmental Quality, P.O. Box 44096, Baton Rouge, Louisiana 70804.
State of Maine, Department of Environmental Protection, State House, Augusta, Maine 04330.
State of Maryland, Air Management Administration, Maryland Department of

the Environment, 2500 Broening Highway, Baltimore, Maryland 21224.

Commonwealth of Massachusetts, Massachusetts Department of Environmental Quality Engineering, Division of Air Quality Control, One Winter Street, Boston, Massachusetts 02108.

State of Michigan, Air Pollution Control Division, Michigan Department of Natural Resources, Stevens T. Mason Building, 8th Floor, Lansing, Michigan 48926.

State of Minnesota, Minnesota Pollution Control Agency, Division of Air Quality, 520 Lafayette Road, St. Paul, Minnesota 55155.

State of Mississippi, Bureau of Pollution Control, Department of Natural Resources, P.O. Box 10385, Jackson, Mississippi 39209.

State of Missouri, Department of Natural Resources, Air Pollution Control Program, P.O. Box 176, Jefferson City, Missouri 65102.

State of Montana, Department of Health and Environmental Services, Cogswell Building, Helena, Montana 59601.

State of Nebraska, Department of Environmental Control, Air Quality Division, P.O. Box 98922, State House Station, Lincoln, Nebraska 68509–8922.

State of Nevada, Department of Conservation and Natural Resources, Division of Environmental Protection, 201 South Fall Street, Carson City, Nevada 89710.

State of New Hampshire, New Hampshire Air Resources Agency, Health and Welfare Building, Hazen Drive, Concord, New Hampshire 03301.

State of New Jersey, Department of Environmental Protection, Division of Environmental Quality, Enforcement Element, John Fitch Plaza, CN–027, Trenton, New Jersey 08625.

State of New Mexico, Director, New Mexico Environmental Improvement Division, Health and Environmental Department, 1190 St. Francis Drive, Santa Fe, New Mexico 87503.

State of New York, Department of Environmental Conservation, Division of Air Resources, 50 Wolf Road, New York, New York 12233.

State of North Carolina, Environmental Management Commission, Department of Natural and Economic Resources, Division of Environmental Management, Attention: Air Quality Section, P.O. Box 27687, Raleigh, North Carolina 27611.

State of North Dakota, State Department of Health and Consolidated Laboratories, Division of Environmental Engineering, State Capitol, Bismark, North Dakota 58501.

State of Ohio, Ohio Environmental Protection Agency, 1800 Watermark Drive, Box 1049, Columbus, Ohio 43266–0149.

State of Oklahoma, Oklahoma State Department of Health, Air Quality Service, P.O. Box 53551, Oklahoma City, Oklahoma 73152.

State of Oregon, Department of Environmental Quality, Yeon Building, 522 SW. Fifth, Portland, Oregon 97204.

Commonwealth of Pennsylvania, Department of Environmental Resources, 105 S. Second Street, P.O. Box 2357, Harrisburg, Pennsylvania 17120.

State of Rhode Island, Department of Environmental Management, 204 Cannon Building, Davis Street, Providence, Rhode Island 02908.

State of South Carolina, Office of Environmental Quality Control, Department of Health and Environmental Control, 2600 Bull Street, Columbia, South Carolina 29201.

State of South Dakota, Department of Water and Natural Resources, Office of Air Quality and Solid Waste, Joe Foss Building, 523 East Capitol, Pierre, South Dakota 57501–3181.

State of Tennessee, Department of Public Health, Division of Air Pollution Control, 256 Capitol Hill Building, Nashville, Tennessee 37219.

State of Texas, Air Pollution Control Board, 6330 Highway 290 East, Austin, Texas 78723.

State of Utah, Department of Health, Bureau of Air Quality, 288 North 1460 West, P.O. Box 16690, Salt Lake City, Utah 84116–0690.

State of Vermont, Vermont Agency of Environmental Conservation, Air Pollution Control, State Office Building, Montpelier, Vermont 05602.

Commonwealth of Virginia, Virginia Department of Air Pollution Control, P.O. Box 10089, Ninth Street Office Building, Richmond, Virginia 23219.

State of Washington, Department of Ecology, Olympia, Washington 98504.

State of West Virginia, Air Pollution Control Commission, 1558 Washington Street East, Charleston, West Virginia 25311.

State of Wisconsin, Department of Natural Resources, P.O. Box 7921, Madison, Wisconsin 53707.

§ 75.5 Public availability of information.

The availability to the public of information provided to or otherwise obtained by the Administrator under this part shall be governed by part 2 of this title.

§ 75.6 State authority.

The provisions of this part shall not be construed in any manner to preclude any State or political subdivision thereof from adopting and enforcing any continuous monitoring requirement applicable to an affected source or unit, provided that such standard or limitation does not interfere with an affected facility's conformance with the requirements applicable to such unit or source prescribed under this part.

§ 75.7 Federal authority.

Under authority of section 114 of the Act, the Administrator may,

(a) Secure information needed for the purpose of developing, revising, and implementing any standard under section 412 or 821 of the Act and of determining whether any person is in violation of any such standard or requirement.

(b) Make inspections, conduct tests, examine records, and require the owner or operator of an affected unit to submit information reasonably required for the purpose of developing standards and methods or determining compliance with the provisions of this part.

§ 75.8 Prohibitions.

(a) A violation of any regulation in this part by the owner or operator of an affected unit or his designated representative is a violation of the Act.

(b) No owner or operator of an affected unit or designated representative shall operate the affected unit without complying with the requirements of §§ 75.11 through 75.23 and each appendix of this part.

(c) No owner or operator of an affected unit or designated representative shall use any alternative monitoring system, alternative reference method, or substitute program for the continuous emission monitoring system without having obtained the Administrator's prior written approval in accordance with § 75.21.

(d) No owner or operator or designated representative shall emit or cause to be emitted any SO_2, NO_x, or CO_2, without accounting for all emissions in accordance with the provisions of §§ 75.11 through 75.23.

§ 75.9 Incorporation by reference.

(a) The materials listed below are incorporated by reference in the corresponding sections noted. These incorporations by reference were approved by the Director of the Federal Register on the date listed. These materials are incorporated as they exist on the date of approval, and a notice of any change in these materials will be published in the **Federal Register**. The materials are available for purchase at the corresponding address noted below and are available for inspection at the Office of the Federal Register, room 8401, 1100 L Street, NW., Washington, DC and at the Library (MD–35), U.S. EPA, Research Triangle Park, North Carolina.

(b) The following materials are available for purchase from at least one of the following addresses: American Society for Testing and Material (ASTM), 1916 Race Street, Philadelphia, Pennsylvania 19103; or the University Microfilms International 300 North Zeeb Road, Ann Arbor, Michigan 48106.

(1) ASTM D4177–82, Standard Method for Automatic Sampling of Petroleum and Petroleum Products, IBR approved ____ for appendix D of this part.

(2) AS____TM D 4057–88, Standard Method for Manual Sampling of Petroleum and Petroleum Products, IBR

approved ____ for appendix D of this part.

(3) ASTM D129–64 (Reapproved 1978), Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved ____ for appendix D of this part.

(4) ASTM D1552–88, Standard Test Method for Sulfur in Petroleum Products (High Temperature Method), IBR approved ____ for appendix D of this part.

(5) ASTM D2622–87, Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry, IBR approved ____ or appendix D of this part.

(6) ASTM D4294–83, Standard Test Method for Sulfur in Petroleum Products by Non-Dispersive X-Ray Fluorescence Spectrometry, IBR approved ____ for appendix D of this part.

(7) ASTM D941–88, Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Lipkin Bicapillary Pycnometer, IBR approved ____ for appendix D of this part.

(8) ASTM D1217–86, Standard Test Method for Density and Relative Density (Specific Gravity) of Liquids by Bingham Pycnometer, IBR approved ____ for appendix D of this part.

(9) ASTM D1481–86, Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Lipkin Bicapillary Pycnometer, IBR approved ____ for appendix D of this part.

(10) ASTM D1480–86, Standard Test Method for Density and Relative Density (Specific Gravity) of Viscous Materials by Bingham Pycnometer, IBR approved ____ for appendix D of this part.

(11) ASTM D1298–85, Standard Test Method for Density, Relative Density (Specific Gravity) or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method, IBR approved ____ for appendix D of this part.

(12) ASTM D4052–86, Standard Test Method for Density and Relative Density of Liquids by Digital Density Meter, IBR approved ____ for appendix D of this part.

(13) ASTM D1250–80 (Reapproved 1984), Standard Petroleum Measurement Tables, IBR approved ____ for appendix D of this part.

(14) ASTM D240–87, Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved ____ for appendices D and E of this part.

(15) ASTM D2382–88, Test Method for Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved ____ for appendices D and E of this part.

(16) ASTM D3178–89, Standard Method for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, IBR approved ____ for appendix E of this part.

(17) ASTM D3176–89, Standard Method for Ultimate Analysis of Coal and Coke, IBR approved ____ for appendix E of this part.

(18) ASTM D1945–81, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved ____ for appendix E of this part.

(19) ASTM D1946–90, Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved ____ for appendix E of this part.

(20) ASTM D2015–85, Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter, IBR approved ____ for appendix E of this part.

(21) ASTM D388–90, Standard Specification for Classification of Coals by Rank, incorporation by reference (IBR) approved ____ for appendix E of this part.

(22) ASTM D1826–88, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved ____ for appendix E of this part.

(23) ASTM D2502–87, Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements, IBR approved ____ for appendix E of this part.

(24) ASTM D2503–82 (Reapproved 1987), Standard Test Method for Molecular Weight of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure, IBR approved ____ for appendix E of this part.

(25) ASTM D3238–85, Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method, IBR approved ____ for appendix E of this part.

(26) ASTM D2234–89, Standard Test Methods for Collection of a Gross Sample of Coal, IBR approved ____ for appendix C of this part.

(27) ASTM D3177–89, Standard Test Methods for Total Sulfur in the Analysis Sample of Coal and Coke, IBR approved ____ for appendix C of this part.

Subpart B—Standards

§ 75.10 Applicability.

(a) The provisions of this part apply to each existing affected unit subject to the Acid Rain Program, pursuant to the requirements of 40 CFR part 72.

(b) The provisions of this part apply to each new utility unit upon commencement of commercial operation.

(c) The provisions of this part apply to each new unit and, except as provided by 40 CFR part 74, to each existing utility unit or nonutility unit that opts into the Acid Rain Program.

§ 75.11 Monitoring of emissions and operations.

(a) The owner or operator shall install, certify, operate, and maintain a continuous emission monitoring system on each affected unit, and record the output of the system, for measuring emissions of SO_2 (ppm) and NO_x (lb/mmBtu) and the volumetric flow (scfh) except as specified in this paragraph or elsewhere in this part. Each continuous emission monitoring system required by this part shall meet the installation, equipment, and performance specifications in appendix A of this part.

(1) If the continuous emission monitoring system is installed such that any portion of the flue gases from an affected unit can by-pass the monitoring system, the owner or operator shall install, certify, operate, and maintain a separate continuous emission monitoring system on the by-pass flue, duct, or stack gas stream.

(2) Where two or more affected units or where affected units and nonaffected units utilize a common stack, the owner or operator shall comply with one of the following methods for monitoring SO_2 emissions (ppm) and volumetric flow (scfh).

(i) Where two or more affected units utilize a common stack, the owner or operator shall either:

(A) Combine allowances for compliance purposes according to the procedures in 40 CFR part 73 and install, operate, and maintain a single continuous emission monitoring system, consisting of an SO_2 pollutant concentration monitor and a flow monitor meeting the requirements of appendix A of this part (referred to hereafter as a "fully certified SO_2 continuous emission monitoring system"), for the combined effluent; or

(B) Monitor the emissions from each unit in the ducts to the common stack with fully certified SO_2 continuous emission monitoring systems.

(ii) Where Phase I affected unit(s) and Phase II affected unit(s) utilize a common stack, the owner or operator shall designate the Phase II unit(s) as a substitution unit(s) pursuant to 40 CFR 72.41, and comply with paragraph (a)(2)(i) of this section, except as

provided in paragraph (a)(2)(v) of this section.

(iii) Where affected unit(s) and nonaffected unit(s) utilize a common stack, the owner or operator shall designate the nonaffected unit(s) as "opt-in" unit(s) and submit an opt-in plan in accordance with the provisions of 40 CFR 72.50 and 40 CFR part 74, and comply with paragraph (a)(2)(i) of this section, except as provided in paragraph (a)(2)(v) of this section.

(iv) Where an affected Phase I unit and a new unit utilize a common stack, the owner or operator shall submit a permit application for the new unit in accordance with the requirements for Phase I affected units as specified in 40 CFR part 72, and comply with paragraph (a)(2)(i) of this section, except as provided in paragraph (a)(2)(v) of this section.

(v) The requirements of paragraphs (a)(2)(ii), (a)(2)(iii), and (a)(2)(iv) of this section shall not apply where the owner or operator installs, operates, and maintains a fully certified SO_2 continuous emission monitoring system in the common stack for monitoring the combined effluent from the affected unit(s) and nonaffected unit(s) and employs one of the following methods to account for emissions from the affected unit(s).

(A) Monitors the emissions from the nonaffected unit(s) in the duct(s) to the common stack and calculates the emissions from the affected unit(s) as the difference between the emissions measured in the common stack and the emissions measured in the duct(s) from the nonaffected unit(s).

(B) Develops, demonstrates, and provides information and data to the Administrator on methods for apportioning the emissions measured in the common stack to individual affected unit(s) and to the nonaffected unit(s). The Administrator may approve such demonstrated substitute methods for apportioning emissions measured in a common stack whenever the demonstration ensures complete and accurate accounting of all emissions regulated under this part.

(3) Where two or more affected units or where affected units and nonaffected units utilize a common stack, the owner or operator shall comply with one of the following methods for monitoring the NO_x emission rate (lb/mmBtu).

(i) Where two or more units utilize a common stack, and all units are not subject to any NO_x emission limitation under 40 CFR part 76 or all units are subject to the same NO_x emission limitation, the owner or operator shall either:

(A) Install, operate, and maintain a single continuous emission monitoring system for NO_x emission rate, consisting of a NO_x pollutant concentration monitor and a diluent gas monitor meeting the requirements of appendix A of this part (referred to hereafter as a "fully certified NO_x continuous emission monitoring system") and, if appropriate, submit a NO_x emissions averaging plan for the units in accordance with 40 CFR parts 72 and 76; or

(B) Monitor the emissions from each unit in the ducts to the common stack with fully certified NO_x continuous emission monitoring systems.

(ii) Where two or more affected units utilize a common stack and the units are subject to different NO_x emission limitations under 40 CFR part 76, the owner or operator shall either:

(A) Install, operate, and maintain a fully certified NO_x continuous emission monitoring system in the common stack and either comply with the most stringent NO_x emission limitation or submit a NO_x emissions averaging plan for the units in accordance with 40 CFR parts 72 and 76; or

(B) Monitor the NO_x emission rate from each unit in the duct to the common stack with fully certified NO_x continuous emission monitoring systems and apportion total emissions to each unit by applying to the Administrator as described in paragraph (a)(2)(v)(B) of this section.

(iii) Where two or more affected units utilize a common stack, and one or more units is not subject to a NO_x emission limitation and one or more units is subject to a NO_x emission limitation under 40 CFR part 76, the owner or operator shall either:

(A) Monitor the NO_x emission rate from each unit in the ducts to the common stack with fully certified NO_x continuous emission monitoring systems and apportion total emissions to each unit with a NO_x emission limitation by applying to the Administrator as described in paragraph (a)(2)(v)(B) of this section; or

(B) Use the method specified in paragraph (a)(2)(v)(A) of this section to calculate the NO_x emission rate(s) for unit(s) with a NO_x emissions limitation and apportion total emissions to each such unit by applying to the Administrator as described in paragraph (a)(2)(v)(B) of this section.

(iv) Where affected unit(s) and nonaffected unit(s) utilize a common stack and one or more of the affected units is subject to a NO_x emission limitation under 40 CFR part 76 the owner or operator shall either:

(A) Comply with the provisions specified in paragraph (a)(3)(iii) of this section; or

(B) Comply with the provisions specified in paragraph (a)(2)(iii) of this section and install, operate, and maintain a fully certified NO_x continuous emission monitoring system along with each fully certified SO_2 continuous emission monitoring system.

(b) Where the SO_2 pollutant concentration monitor measures emissions on a dry basis, the owner or operator shall install and operate a moisture monitor or continuously account for the moisture content of the gas.

(c) The owner or operator shall determine the total annual CO_2 emissions (tons) from each affected unit as required by this part.

(d) The owner or operator shall install, operate, and maintain a continuous monitoring system on each affected unit, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere as required by this part.

(e) Each continuous emission monitoring system and continuous opacity monitoring system required by this part shall be installed, certified, and operational on or before:

(1) November 15, 1993, for each Phase I affected unit.

(2) January 1, 1995, for each Phase II affected unit that has not already met the requirements of this part.

(3) The date on which a substitution unit becomes an affected unit in accordance with 40 CFR part 74.

(4) The date on which a new unit commences commercial operation.

(f) All continuous monitoring systems shall be installed and operational prior to conducting initial certification tests under § 75.19. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the system or component.

(g) Prior to the operational date given in paragraph (e) of this section, all data acquisition and handling systems installed as a part of the continuous emission monitoring system shall be certified to produce valid calculations of the emissions in terms of the standard (e.g., lb/hr for SO_2 and lb/mmBtu for NO_x) from the data generated by the component analyzers in the continuous emission monitoring system.

(h) The owner or operator shall convert all emissions into units of the applicable allowance or emission limit by means of the data acquisition and

handling system, using the conversion procedures in appendix E of this part.

(i) Except for system breakdowns, repairs, and routine adjustments required under § 75.20, all continuous emission monitoring systems and continuous opacity monitoring systems required by this part shall be in operation at all times during the operation of the affected unit and shall meet the following requirements.

(1) Each continuous emission monitoring system and component thereof shall be capable of completing a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-min interval. All SO_2 pollutant concentration, volumetric flow, and NO_x emission rate data shall be reduced to 1-hr averages. These averages shall be computed from four or more data points equally spaced over each 1-hr period, except for periods of calibration, quality assurance activities, maintenance or repair. During these periods, a valid hour shall consist of at least two data points with each representing a 15-min period and a cycle of operation as described above.

(2) All continuous opacity monitoring systems shall complete a minimum of one cycle of sampling and analyzing for each successive 10-sec period and one cycle of data recording for each successive 6-min period. All opacity data shall be reduced to 6-min averages calculated from 36 or more data points equally spaced over each 6-min period, except where a different averaging period is required and specified in the applicable State implementation plan or operating permit.

(j) Failure of the continuous emission monitoring system to acquire four valid data points, except for periods of calibration, quality assurance activities, maintenance or repair, shall result in the loss of such data for the entire hour and the owner or operator shall record and report data by means of the data acquisition and handling system for the missing hour in accordance with the applicable procedures for obtaining missing data in §§ 75.12, 75.13, and 75.14.

(k) The owner or operator shall account for all heat input to each affected unit for every hour or part of an hour that fuel is combusted following the procedures in appendix E of this part and shall record and report the heat input in accordance with §§ 75.22 and 75.23.

(l) An affected unit for which the designated representative and the owner or operator submit a certified commitment, as required in § 75.23(i), to retire such unit permanently prior to January 1, 1995, is exempt from the requirements of this part.

(m) Substitution units shall be subject to all the continuous emission monitoring requirements applicable to Phase I units.

§ 75.12 Monitoring of SO_2 emissions.

(a) The owner or operator shall install, operate, and maintain an SO_2 pollutant concentration monitor and data acquisition and handling system for measuring and recording the concentration (in ppm) of SO_2 emissions discharged to the atmosphere on each affected unit except as provided in paragraphs (b) and (c) of this section and elsewhere in this part.

(b) Gas-fired units. The owner or operator of an affected gas-fired unit may install, operate, and maintain an SO_2 pollutant concentration monitor (with a flow monitor) or provide other information satisfactory to the Administrator using the procedure for providing hourly SO_2 emissions data in appendix D of this part.

(c) Oil-fired units. The owner or operator of an affected oil-fired unit may install, operate, and maintain an SO_2 pollutant concentration monitor (with a flow monitor) or provide other information satisfactory to the Administrator using the procedure for providing hourly SO_2 emissions data in appendix D of this part.

(d) Phase I qualifying technology. The owner or operator of an affected unit for which a Phase I qualifying technology has been installed shall install, certify, operate, and maintain a continuous emission monitoring system for the measurement of SO_2 emissions at the inlet to the SO_2 emission controls in addition to a continuous emission monitoring system downstream of the SO_2 emission controls for the measurement of SO_2 emissions discharged to the atmosphere. Each of these continuous emission monitoring systems shall measure the SO_2 emissions rate (in lb/mmBtu) and shall consist of an SO_2 pollutant concentration monitor and a diluent gas monitor for measuring the O_2 or CO_2 concentration of the flue gas.

(1) The SO_2 pollutant concentration monitors and the diluent gas monitors at the inlet and downstream (outlet) of the SO_2 emission controls shall meet all requirements specified in appendices A and B of this part.

(2) The owner or operator shall demonstrate that the SO_2 emission controls are a Phase I qualifying technology achieving at least a 90 percent SO_2 emission removal efficiency according to the following procedures.

(i) No later than 90 days after the startup of the SO_2 emission controls and any other time required by 40 CFR part 72, the owner or operator shall conduct a 30-day test for SO_2 emissions removal efficiency. The average SO_2 emissions removal efficiency during the 30-day test shall be calculated using the following equations.

$$\%R = 100\,[1.0-(1.0-\%R_f/100)(1.0-\%R_g/100)] \quad \text{(Eq. 1)}$$

where:

$\%R$ = Overall percentage SO_2 emissions removal efficiency.

$\%R_f$ = Percentage SO_2 emissions removal efficiency from fuel pretreatment, calculated from Equation 19–22 in Reference Method 19, 40 CFR part 60, appendix A.

$\%R_g$ = Percentage SO_2 removal efficiency of the emission controls calculated from Equation 2 below.

$$\%R_g = 100\left[1.0-\frac{E_o}{E_i}\right] \quad \text{(Eq. 2)}$$

where:

E_o = Average hourly SO_2 emission rate in lb/mmBtu, measured at the outlet of the emission controls during the startup test (or calendar year).

E_i = Average hourly SO_2 emission rate in lb/mmBtu, measured at the inlet to the emission controls during the startup test (or calendar year).

$$E_o = \frac{\sum_{j=1}^{n} E_{hoj}}{n} \quad \text{(Eq. 3)}$$

where:

E_{hoj} = Each hourly SO_2 emission rate in lb/mmBtu, measured by the continuous emission monitoring system at the outlet to the emission controls.

n = Total unit operating hours during which the SO_2 continuous emission monitoring system at the outlet of the emission controls collected quality-assured data.

$$E_i = \frac{\sum_{j=1}^{m} E_{hij}}{m} \quad \text{(Eq. 4)}$$

where:

E_{hij} = Each hourly SO_2 emission rate in lb/mmBtu, measured by the continuous emission monitoring system at the inlet to the emission controls.

m = Total unit operating hours during which the SO_2 continuous emission monitoring system at the inlet to the emission controls collected quality-assured data.

(ii) Total operating hours for the purpose of computing the average SO_2

emissions removal efficiency during the 30-day test shall include all periods when fuel is being combusted except for periods of startup, shutdown, and malfunction.

(iii) The owner or operator shall record and report the results of the initial 30-day test as specified in § 75.22(e) and § 75.23(e).

(iv) Compliance with the 90-percent SO_2 emissions removal efficiency requirement under this part is determined annually from the date of startup of the SO_2 emission controls through 1999, using the average inlet and average outlet SO_2 emission rates, (in lb/mmBtu) during the calendar year. Each annual average percent reduction shall be calculated using Equations 1 through 4 above. Total operating hours for the purpose of computing annual average SO_2 emissions removal efficiency shall include all periods when fuel is being combusted including periods of startup, shutdown, and malfunction. The owner or operator shall record and report quarterly and annual average SO_2 emissions removal efficiency as specified in § 75.22 and § 75.23.

(v) The owner or operator shall use all valid hourly SO_2 emissions data (lb/mmBtu) measured and recorded by the SO_2 continuous emission monitoring system to calculate the initial 30-day and annual average percent SO_2 emissions removal efficiency.

(A) Only quality-assured SO_2 emissions data measured by the inlet and outlet SO_2 pollutant concentration and diluent gas monitors shall be used in the calculation of SO_2 emissions removal efficiency.

(B) The owner or operator shall use a minimum of 20 hours of data for each unit operating day during the startup test. A minimum of 600 hours of data is required during the startup test. If the number of hours of data during the startup test falls below the minimum requirement, the owner or operator shall repeat the test for an additional 30 days.

(e) *Missing data procedures.* For each affected unit, the owner or operator shall provide substitute data as described below whenever a valid hour of SO_2 pollutant concentration data (in ppm) has not been obtained and recorded.

(1) The owner or operator shall calculate daily, by means of the data acquisition and handling system, the percent of data availability from the SO_2 pollutant concentration monitor for the previous 365 calendar days using the following equation.

$$\text{Percent annual monitor availability} = \frac{\text{Total unit operating hours for which monitor provided quality-assured data during previous 365 calendar days}}{\text{Total unit operating hours during previous 365 calendar days}} \times 100 \quad \text{(Eq. 5)}$$

(2) The owner or operator shall record the percent annual monitor availability daily and report as required in § 75.23.

(3) Except as provided in paragraph (e)(6) of this section, whenever data from the SO_2 pollutant concentration monitor have been available and recorded for 95.0 percent or more of the total unit operating hours during the previous 365 calendar days, the owner or operator shall calculate substitute data by means of the data acquisition and handling system for each hour of each missing data period according to the following procedures.

(i) For a missing data period less than or equal to 24 hours, substitute the average of the hourly SO_2 pollutant concentrations recorded by the monitor for the hour immediately before and the hour immediately following the missing data period.

(ii) For a missing data period greater than 24 hours, substitute the greater of the following values:

(A) 90th percentile hourly SO_2 concentration recorded by the monitor at the corresponding sulfur content range recorded for the missing hour during the previous 30 days of operation as determined using the procedure in section 4 of appendix C of this part; or

(B) Average of the hourly SO_2 pollutant concentrations recorded by the monitor for the hour immediately before and the hour immediately following the missing data period.

(4) Except as provided in paragraph (e)(6) of this section, whenever data from the SO_2 pollutant concentration monitor have been available and recorded for at least 90.0 percent but less than 95.0 percent of the total unit operating hours during the previous 365 calendar days, the owner or operator shall calculate substitute data by means of the data acquisition and handling system for each hour of each missing data period according to the following procedures.

(i) For a missing data period of less than or equal to 6 hours, substitute the average of the hourly SO_2 concentrations recorded by the monitor for the hour immediately before and the hour immediately following the missing data period.

(ii) For a missing data period of more than 6 hours but less than or equal to 24 hours, substitute the greater of the following values:

(A) 90th percentile hourly SO_2 concentration recorded by the monitor at the corresponding sulfur content range recorded for the missing hour during the previous 30 days of operation as determined using the procedure in section 4 of appendix C of this part; or

(B) Average of the hourly SO_2 pollutant concentrations recorded by the monitor for the hour immediately before and the hour immediately following the missing data period.

(iii) For a missing data period of more than 24 hours, substitute the greater of the following values:

(A) 90th percentile hourly SO_2 concentration recorded by the monitor at the corresponding sulfur content range recorded for the missing hour during the previous 365 days of operation as determined using the procedure in section 4 of appendix C of this part; or

(B) Average of the hourly SO_2 pollutant concentrations recorded by the monitor for the hour immediately before and the hour immediately following the missing data period.

(5) Whenever data from the SO_2 pollutant concentration monitor have been available and recorded less than 90.0 percent of the total unit operating hours during the previous 365 calendar days, substitute for each hour of each missing data period, the greater of the following values:

(i) 90th percentile hourly SO_2 concentration recorded by the monitor at the corresponding sulfur content range recorded for the missing hour during the previous 365 days of operation as determined using the procedure in section 4 of appendix C of this part; or

(ii) Average of the hourly SO_2 pollutant concentrations recorded by the monitor for the hour immediately before and the hour immediately following the missing data period.

(6) When the affected unit is equipped with SO_2 emission controls and data from the SO_2 pollutant concentration monitor have been available and recorded for 90.0 percent or more of the total unit operating hours during the previous 365 calendar days, the owner or operator may petition the Administrator to certify a parametric monitoring procedure, as described in appendix C of this part, for calculating substitute data for missing data periods. The owner or operator shall use the procedures in paragraphs (d)(3) and (d)(4) of this section prior to receiving the Administrator's certification for a parametric monitoring procedure for filling in missing SO_2 pollutant concentration data.

(7) For an affected unit with SO_2 emission controls, where the data from the SO_2 pollutant concentration monitor have been available and recorded for less than 90.0 percent of the total unit operating hours during the previous 365 calendar days, the owner or operator shall calculate substitute data using the procedures in paragraph (d)(5) of this section.

(8) When the affected unit is equipped with SO_2 emission controls, the owner or operator shall provide information satisfactory to the Administrator as described in §§ 75.22 and 75.23 to verify the proper operation of the SO_2 emission controls for all periods of missing data. Whenever such data are not provided or proper operation of the SO_2 emission controls has not been maintained, the uncontrolled emission rate shall apply.

§ 75.13 Monitoring of volumetric flow.

(a) The owner or operator shall install, operate, and maintain a flow monitor and data acquisition and handling system for the continuous measurement and recording of the volumetric flow (in scfh) on each affected unit, except as provided in paragraphs (a) (1) and (2) of this section and in § 75.21.

(1) Gas-fired units. The owner or operator of an affected gas-fired unit may install, operate, and maintain a flow monitor (with an SO_2 pollutant concentration monitor) or provide other information satisfactory to the Administrator using the procedure for providing SO_2 emissions data in appendix D of this part.

(2) Oil-fired units. The owner or operator of an affected oil-fired unit may install, operate, and maintain a flow monitor (with an SO_2 pollutant concentration monitor) or provide other information satisfactory to the Administrator using the procedure for providing hourly SO_2 emissions data in appendix D of this part.

(3) Where no location exists in the existing ducts or stack that is greater than or equal to two stack or duct diameters downstream or one-half duct diameter upstream from a flow disturbance in accordance with the minimum siting criteria of appendix A of this part, the owner or operator may petition the Administrator for an alternative monitoring location or monitoring method. The owner or operator electing to petition the Administrator for an alternative monitoring method shall report the information and data as described in § 75.23.

(b) Moisture. The owner or operator of an affected unit equipped with an SO_2 pollutant concentration monitor that measures on a dry basis shall determine the moisture content of the flue gases continuously (or on an hourly basis) and correct the measured hourly flow rates for moisture when calculating the SO_2 emissions using the procedures in appendix E of this part. The flow monitor shall meet all of the required specifications in appendix A of this part after the correction for the moisture content of the flue gases.

(c) Missing data procedures. For each affected unit, the owner or operator shall provide substitute data as described below whenever a valid hour of flow data (in scfh) has not been obtained and recorded.

(1) The owner or operator shall calculate daily, by means of the data acquisition and handling system, the percent annual monitor availability of the flow monitor over the previous 365 calendar days using Equation 5 in § 75.12(e).

(2) The owner or operator shall record the percent annual monitor availability daily and report as required in § 75.23.

(3) Whenever data from the flow monitor have been available and recorded for 95.0 percent or more of the total operating hours for the unit during the previous 365 calendar days, the owner or operator shall calculate substitute data by means of the data acquisition and handling system for each hour of each missing data period according to the following procedures.

(i) For a missing data period less than or equal to 24 hours, substitute the average hourly flow rate recorded by the monitor during the previous 365 days at the corresponding unit load range recorded for the missing hour, as determined using the procedure in section 3 of appendix C of this part.

(ii) For a missing data period greater than 24 hours, substitute the greater of the following values:

(A) 90th percentile hourly flow rate recorded by the monitor at the corresponding unit load range recorded for the missing hour during the previous 30 days of operation, as determined using the procedure in section 3 of appendix C of this part; or

(B) Average hourly flow rate recorded by the monitor at the corresponding unit load range recorded for the missing hour during the previous 365 days of operation, as determined using the procedure in section 3 of appendix C of this part.

(4) Whenever data from the flow monitor have been available and recorded for at least 90.0 percent but less than 95.0 percent of the total unit operating hours during the previous 365 calendar days, the owner or operator shall calculate substitute data by means of the data acquisition and handling system for each hour of each missing data period according to the following procedures.

(i) For a missing data period of less than or equal to 6 hours, substitute the average hourly flow rate recorded by the monitor at the corresponding unit load range recorded for the missing hour during the previous 365 days of operation, as determined using the procedure in section 3 of appendix C of this part.

(ii) For a missing data period greater than 6 hours but less than or equal to 24 hours, substitute the greater of the following values:

(A) 90th percentile hourly flow rate recorded by the monitor at the corresponding unit load range recorded for the missing hour during the previous 30 days of operation, as determined using the procedure in section 3 of appendix C of this part; or

(B) Average hourly flow rate recorded by the monitor at the corresponding unit load range recorded for the missing hour during the previous 365 days of operation, as determined using the load based procedure in section 3 of appendix C of this part.

(iii) For a missing data period greater than 24 hours, substitute the 90th percentile hourly flow rate recorded by the monitor at the corresponding unit load range recorded for the missing hour during the previous 365 days of operation, as determined using the procedure in section 3 of appendix C of this part.

(5) Whenever data from the flow monitor have been available and recorded for less than 90.0 percent of the total unit operating hours during the previous 365 calendar days, substitute the 90th percentile hourly flow rate recorded by the monitor at the corresponding unit load range recorded for the missing hour during the previous

365 days of operation, as determined using the procedure in section 3 of appendix C of this part.

§ 75.14 Monitoring of No$_x$ emissions.

(a) The owner or operator shall install, operate and maintain a continuous emission monitoring system and data acquisition and handling system for measuring and recording NO_x emissions (in lb/mmBtu) discharged to the atmosphere on each affected unit except as provided in § 75.21. The continuous emission monitoring system shall consist of a NO_x pollutant concentration monitor for measuring the concentration (in ppm) of NO_x emissions and a diluent gas monitor for measuring the O_2 or CO_2 content of the flue gases.

(b) Hourly, quarterly, and annual NO_x emission rates shall be calculated by combining the NO_x and diluent (O_2 or CO_2) concentration values in accordance with the procedures in appendix E of this part.

(c) Missing data procedures. For each affected unit, the owner or operator shall provide substitute data as described below whenever a valid hour of NO_x emission rate data has not been obtained and recorded.

(1) The owner or operator shall calculate daily, by means of the data acquisition and handling system, the percent annual availability of the NO_x continuous emission monitoring system over the previous 365 calendar days using Equation 5 in § 75.12(e).

(2) The owner or operator shall record the percent annual monitor availability daily and report as required in § 75.23.

(3) Except as provided in paragraph (c)(6) of this section, whenever data from the NO_x continuous emission monitoring system have been available and recorded for 95.0 percent or more of the total unit operating hours during the previous 365 calendar days, the owner or operator shall calculate substitute data by means of the data acquisition and handling system for each hour of each missing data period according to the following procedures.

(i) For a missing data period less than or equal to 24 hours, substitute the average hourly NO_x emission rate (in lb/mmBtu) recorded by the system days at the corresponding unit load range recorded for the missing hour during the previous 365 days of operation, as determined using the procedure in section 3 of appendix C of this part.

(ii) For a missing data period greater than 24 hours, substitute greater of the following values:

(A) 90th percentile hourly NO_x emission rate recorded by the system at the corresponding unit load range recorded for the missing hour during the previous 30 days of operation, as determined using the procedure in section 3 of appendix C of this part; or

(B) Average hourly NO_x emission rate recorded by the system at the corresponding unit load range recorded for the missing hour during the previous 365 days of operation, as determined using the procedure in section 3 of appendix C of this part.

(4) Except as provided in paragraph (c)(6) of this section, whenever data from the NO_x continuous emission monitoring system have been available for at least 90.0 percent but less than 95.0 percent of the total unit operating hours during the previous 365 calendar days, the owner or operator shall calculate substitute data for each hour of each missing data period according to the following procedures.

(i) For a missing data period of less than or equal to 6 hours, substitute the average hourly NO_x emission rate recorded by the system at the corresponding unit load range recorded for the missing hour during the previous 365 days of operation, as determined using the procedure in section 3 of appendix C of this part.

(ii) For a missing data period of greater than 6 hours but less than or equal to 24 hours, substitute the greater of the following values:

(A) 90th percentile hourly NO_x emission rate recorded by the system at the corresponding unit load range recorded for the missing hour during the previous 30 days of operation, as determined using the procedure in section 3 of appendix C of this part.

(B) Average hourly NO_x emission rate recorded by the monitor at the corresponding unit load range recorded for the missing hour during the previous 365 days of operation, as determined using the procedure in section 3 of appendix C of this part.

(iii) For a missing data period greater than 24 hours, substitute the 90th percentile hourly NO_x emission rate recorded by the system at the corresponding unit load range recorded for the missing hour during the previous 365 days of operation, as determined using the procedure in section 3 of appendix C of this part.

(5) Whenever data from the NO_x continuous emission monitoring system have been available less than 90.0 percent of the total unit operating hours during the previous 365 calendar days, substitute for each hour in each missing data period the 90th percentile hourly NO_x emission rate at the corresponding unit load range recorded for the missing hour during the previous 365 days of operation, as determined using the procedure in section 3 of appendix C of this part.

(6) When the affected unit is equipped with post-combustion NO_x emission controls, and data from the NO_x continuous emission monitoring system have been available and recorded for 90.0 percent or more of the total operating hours during the previous 365 calendar days, the owner or operator may petition the Administrator to certify a parametric monitoring procedure, as described in appendix C of this part, for calculating substitute data for missing data periods. The owner or operator shall use the procedures in paragraphs (c)(3) and (c)(4) of this section prior to receiving the Administrator's certification for a parametric monitoring procedure for filling in missing NO_x emission rate data.

(7) When the affected unit is equipped with post-combustion NO_x emission controls, and data from the NO_x continuous emission monitoring system have been available for less than 90.0 percent of the total operating hours during the previous 365 calendar days, the owner or operator shall use the procedure in paragraph (c)(5) of this section for calculating substitute data for missing data periods.

(8) When the affected unit is equipped with post-combustion NO_x emission controls, the owner or operator shall provide information satisfactory to the Administrator as described in §§ 75.22 and 75.23 of this part to verify the proper operation of the NO_x removal system during all periods of missing data. Whenever such data are not provided or proper operation of the post-combustion NO_x emission controls has not been maintained, the uncontrolled emission rate shall apply.

§ 75.15 Monitoring of CO_2 emissions

(a) Except as provided in paragraph (b) of this section, each owner or operator shall monitor CO_2 emissions (in lb/day) discharged to the atmosphere from each affected unit using either of the following methods.

(1) Install, operate, and maintain a continuous emission monitoring system and a data acquisition and handling system to measure and record the CO_2 emission rate (in lb/hr) using the procedures in appendix E of this part. The continuous emission monitoring system shall consist of a CO_2 diluent gas monitor for measuring the concentration (in ppm) of CO_2 and a flow monitor for measuring the volumetric flow rate (in scfh) of the flue gas. Daily and annual CO_2 emissions shall be obtained by summing hourly emissions data.

(2) Calculate, using the methods and procedures specified in appendix E of this part, combustion-related CO_2 mass emissions (in lb/day) based on the measured carbon content of the fuel and the amount of fuel combusted. Annual CO_2 emissions shall be obtained by summing daily CO_2 emission estimates.

(b) When the affected unit is equipped with a wet limestone flue gas desulfurization system, a fluidized-bed combustion unit with limestone as the sorbent material, or another system that generates CO_2 from input materials other than fuel, the owner or operator shall account for all CO_2 emissions generated by the system. The owner or operator may either install, operate, and maintain a CO_2 continuous emission monitoring system to measure the total hourly, daily, and annual emissions or calculate both the combustion-related and sorbent-related CO_2 emissions using the procedures in appendix E of this part.

§ 75.16 Monitoring of opacity.

(a) The owner or operator shall install, operate, and maintain a continuous opacity monitoring system on each affected unit, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere, except as provided in paragraphs (b) and (c) of this section. Each continuous opacity monitoring system shall meet the installation, equipment, and performance specifications in Performance Specification 1 in appendix B of 40 CFR part 60.

(b) Gas-fired units. The owner or operator of an affected gas-fired affected unit is exempt from the opacity monitoring requirements of this part.

(c) Units with wet flue gas desulfurization systems. The owner or operator of an affected unit equipped with a wet flue gas desulfurization system for SO_2 emissions control is exempt from the opacity monitoring requirements of this part.

§ 75.17 Reference methods for certification

(a) The owner or operator shall use the following methods to conduct monitoring system certification tests for certification or recertification of continuous emission monitoring systems and quality assurance and quality control procedures.

(1) Method 1 is the reference method for selection of sampling site and sample traverses.

(2) Method 2 is the reference method for determination of volumetric flow.

(3) Methods 3 or 3A are the reference methods for the determination of the dry molecular weight O_2 and CO_2 concentrations in the emissions.

(4) Method 4 is the reference method for the determination of moisture in the stack.

(5) Methods 6, 6A, 6B or 6C, and 7, 7A, 7B, 7C, 7D or 7E, as applicable, are the reference methods for determining SO_2 and NO_x pollutant concentrations.

(b) Each of the methods identified in paragraph (a) of this section may be found in appendix A of 40 CFR part 60.

§ 75.18 Certification procedures.

(a) Each continuous emission monitoring system shall be certified prior to use under Title IV of the Act. Recertification is required following any change in the continuous emission monitoring system that could adversely affect the ability of the system or procedure to measure or record the appropriate pollutant mass emission rate, volumetric flow, or concentration (e.g., change in gas cells, path lengths, probe, or system optics). Only output as recorded by the data acquisition and handling system shall be used for the comparison of monitor measurements to the reference method values during certification or recertification.

(1) To obtain certification or recertification of a continuous emission monitoring system for pollutant concentration, emission rate, and/or volumetric flow, the owner or operator shall submit a formal request to the Administrator and shall provide a copy of the submission to the appropriate State air pollution control agency and the applicable Regional Administrator.

(2) The owner or operator shall include the reports and information specified in § 75.23(b) in each request for certification or recertification. A complete request for certification or recertification shall consist of all required information, including certification test results.

(3) Following review of the request and supporting documentation, the Administrator will issue a written notice of approval or disapproval to the owner or operator within 120 days of receipt of a complete request for certification or recertification.

(4) Any complete request for certification or recertification that meets the requirements of this part and for which a notice of approval is not issued within 120 days of receipt will be automatically certified for use under title IV of the Act.

(5) The owner or operator of an affected unit for which certification or recertification is disapproved shall revise equipment, procedures, or methods as needed and resubmit a request for certification or recertification according to the procedures in this section.

(6) Whenever a request for certification or recertification of a monitor's operation is disapproved, the owner or operator shall use the uncontrolled emission rate to account for the affected unit's emissions until such time as the monitor can be adjusted, repaired, or replaced and certified.

(b) Any alternative monitoring system shall be approved and certified prior to use under Title IV of the Act. Recertification is required following any change in the system or procedure that could affect the ability of the system to measure or record emissions other than routine maintenance or corrective action. To obtain approval and certification of such an alternative monitoring system, the owner or operator shall submit a request for approval and certification or recertification to the Administrator. The Administrator will publish the request in the **Federal Register** and will issue a notice of approval or disapproval following a public comment period of 60 days.

(c) No alternative emissions monitoring system shall be authorized by a permitting authority in a permit issued pursuant to 40 CFR part 72 unless approved by the Administrator in accordance with this part.

§ 75.19 Certification tests.

Prior to the date by which the continuous emission monitoring system must be installed and operational, the owner or operator shall conduct certification tests to demonstrate that the continuous emission monitoring system and components meet the specifications in appendix A of this part. The output from the data acquisition and handling system shall be used to compare the monitor or continuous emission monitoring system measurements to the reference method values during certification tests. As described in appendix A, the following certification tests are to be performed.

(1) For each SO_2 pollutant concentration monitor and NO_x continuous emission monitoring system (i.e., NO_x pollutant concentration monitor and diluent gas monitor), a calibration error test, a relative accuracy test, a bias test, and a cycle time/response time test.

(2) For each flow monitor, a relative accuracy test, a bias test, and a calibration error or electronic drift test, and for each differential pressure flow monitor, an orientation sensitivity test.

(3) For each CO_2 monitor used for continuously monitoring CO_2 emissions, a calibration error test, a relative accuracy test, and a bias test.

(4) For each combined SO_2/flow monitoring system, a relative accuracy test and a bias test (effective January 1, 2000).

(b) Prior to the date by which the continuous opacity monitoring system must be installed and operational, the owner or operator shall conduct certification tests to demonstrate that the continuous opacity monitoring system meets requirements of Performance Specification 1 in 40 CFR part 60, appendix B. As described in Performance Specification 1, the following tests are to be performed.

(1) Calibration error test.

(2) Response time test.

(3) Zero drift test.

(4) Calibration drift test.

(c) The owner or operator shall record and report the results of each certification test as required in §§ 75.22 and 75.23.

(d) A CO_2 monitor certified for use in an NO_x monitoring system shall be deemed to be certified for the purposes of § 75.15.

§ 75.20 Quality assurance and quality control procedures.

(a) The owner or operator of an affected unit shall operate, calibrate, and maintain each continuous emission monitoring system according to the quality assurance and quality control procedures in appendix B of this part.

(b) If an out-of-control period occurs, the owner or operator shall take corrective action and repeat the applicable test as described in appendix B of this part. During the period the monitor or continuous emission monitoring system is out of control, recorded data may not be used in data averages and calculations. The owner or operator shall apply the procedures for missing data until the monitor or monitoring system has successfully met the relevant criteria as demonstrated by a subsequent test.

(1) For calibration error or electronic drift tests, an out-of-control period occurs when the calibration error or electronic drift exceeds twice the applicable specification in appendix A of this part (e.g., when the calibration error of a pollutant concentration monitor exceeds 5.0 percent, the calibration error of a diluent gas monitor exceeds 1.0 percent, or the calibration error or electronic drift of a flow monitor exceeds 6.0 percent).

(2) For relative accuracy, interference, and orientation sensitivity tests, an out-of-control period occurs when the measured value exceeds the applicable specification in appendix A of this part.

(c) The owner or operator of an affected unit shall operate, calibrate, and maintain each continuous opacity monitoring system according to the quality assurance and quality control procedures in Method 203 in 40 CFR part 52, appendix M.

§ 75.21 Alternative monitoring systems.

(a) The owner or operator of an affected unit required to install a continuous emission monitoring system may apply to the Administrator for approval of an alternative monitoring system (or system component) to determine average hourly emission data for SO_2, NO_x, and/or volumetric flow by demonstrating that the alternative monitoring system has the same or better precision, reliability, accessibility, and timeliness as that provided by the continuous emission monitoring system. The following requirements shall be met by the alternative monitoring system when compared to a contemporaneously operating, fully certified continuous emission monitoring system.

(1) To demonstrate precision equal to or better than the continuous emission monitoring system, the owner or operator shall conduct an F-test, a correlation analysis, and a t-test for bias as described in this section. The t-test shall be performed only on sample data at the normal operating level whereas the F-test and the correlation analysis must be performed on each of the data sets required under paragraphs (a)(1)(iv) and (a)(1)(vi) of this section. The owner or operator shall collect and analyze data that meet the following requirements.

(i) Data from the alternative monitoring system and the continuous emission monitoring system are to be collected and paired in a manner that ensures each pair of values applies to hourly average emissions during the same hour.

(ii) An alternative monitoring system that directly measures emissions shall have probes or other measuring devices in locations that are in proximity to the continuous emission monitoring system and shall provide data on the same parameters as those measured by the continuous emission monitoring system. Data from the alternative monitoring system shall meet the statistical tests for precision in paragraph (b) of this section and the t-test for bias in appendix A of this part.

(iii) An alternative monitoring system that indirectly quantifies emission values (e.g., by measuring inputs, operating characteristics, or outputs and then applying a regression or another quantitative technique to estimate emissions) shall meet the statistical tests for precision in paragraph (b) of this section and the t-test for bias in appendix A of this part.

(iv) For flow monitor alternatives, the alternative monitoring system shall provide sample data while the unit (or units, if more than one unit exhausts into the stack or duct) is burning primary fuel at the following gas flows: (A) the minimum safe and stable operating level, (B) 90 percent or greater of the maximum velocity, and (C) the normal operating level or an evenly spaced intermediary velocity if the normal operating level is within 10 percent of paragraph (a)(1)(iv) (A) or (B) of this section.

(v) For pollutant concentration monitor alternatives, the alternative monitoring system shall provide sample data for the normal fuel supply and for all alternative fuel supplies that have significantly different sulfur content.

(vi) For the normal unit operating level and normal fuel supply, paired hourly sample data must be provided for at least 90.0 percent of the hours during 30 successive unit operating days. For each of the remaining two operating levels (for flow monitor alternatives) and for each alternative fuel supply (for pollutant concentration monitor alternatives), paired hourly sample data must be provided for at least 24 successive unit operating hours.

(vii) The owner or operator shall not use missing data procedures to provide sample data.

(viii) If the collected data meet the requirements of the F-test, the correlation test, and the t-test at one or more, but not all, of the operating levels or fuel supplies, the owner or operator may elect to continue collecting the paired data for up to 60 additional days and repeat the statistical tests using the data for the entire 30- to 90- day period.

(ix) The owner or operator shall provide two separate time series data plots for the data at each operating level or fuel supply described in paragraphs (a)(1)(iv) and (a)(1)(v) of this section. Each graph shall have a horizontal axis that represents the clock hour and calendar date of the readings and shall contain a separate data point for every hour for the duration of the performance evaluation. The graphs shall show the following:

(A) Percentage difference versus time where the vertical axis represents the percentage difference between each paired hourly reading generated by the continuous emission monitoring system and the alternative emission monitoring

system as calculated using the following equation:

$$\Delta e = \frac{e_p - e_v}{e_v} \times 100\% \qquad \text{(Eq. 6)}$$

where

Δe = Percentage difference between the readings generated by the alternative monitoring system and the continuous emission monitoring system.

e_p = Measured value from the alternative monitoring system.

e_v = Measured value from the continuous emission monitoring system.

(B) Alternative monitoring system readings and continuous emissions monitoring system readings versus time where the vertical axis represents hourly pollutant concentrations or volumetric flow, as appropriate, and two different symbols are used to represent the readings from the alternative monitoring system and the continuous emission monitoring system, respectively.

(2) To demonstrate reliability equal to or better than the continuous emission monitoring system, the owner or operator shall demonstrate that the alternative monitoring system is capable of providing valid 1-hr averages for 95.0 percent or more of unit operating hours over a 1-yr period and that the system meets the applicable requirements of appendix B of this part.

(3) To demonstrate accessibility equal to or better than the continuous emission monitoring system, the owner or operator shall provide reports and onsite records of emission data to demonstrate that the alternative monitoring system provides data meeting the requirements of §§ 75.22 and 75.23.

(4) To demonstrate timeliness equal to or better than the continuous emission monitoring system, the owner or operator shall demonstrate that the alternative monitoring system can meet the requirements of §§ 75.22 and 75.23; can provide a continuous, quality-assured, permanent record of certified emissions data on an hourly basis; and can issue a record of data for the previous day within 24 hours.

(5) The owner or operator shall either demonstrate that daily tests equivalent to those specified in appendix B of this part can be performed on the alternative monitoring system or demonstrate and document that such tests are unnecessary.

(6) The owner or operator shall demonstrate that all missing data can be accounted for in a manner consistent with the applicable procedures in §§ 75.12 through 75.14.

(b) Statistical tests. The owner or operator shall perform the F-test and correlation analysis as described below to demonstrate the precision of the alternative monitoring system.

(1) *F-test.* The F-test is conducted according to the following procedures:

(i) Calculate the variance of the certified continuous emission monitoring system or certified flow monitor as applicable, S_v^2, and the proposed method, S_p^2, using the following equation:

$$S^2 = \frac{\Sigma(e_i - e_m)2}{n-1} \qquad \text{(Eq. 7)}$$

where

e_i = Measured values of either the certified continuous emission monitoring system or certified flow monitor, as applicable, or proposed method.

e_m = Mean of either the certified continuous emission monitoring system or certified flow monitor, as applicable, or proposed method values.

n = Total number of paired samples.

(ii) Determine if the variance of the proposed method is significantly different from that of the certified continuous emission monitoring system or certified flow monitor, as applicable, by calculating the F-value using the following equation:

$$F = \frac{S_p^2}{S_v^2} \qquad \text{(Eq. 8)}$$

Compare the experimental F-value with the critical value of F at the 95-percent confidence level with n–1 degrees of freedom. The critical value is obtained from a table for F-distribution. If the calculated F-value is greater than the critical value, the proposed method is unacceptable.

(2) *Correlation analysis.* The correlation analysis is conducted according to the following procedures.

(i) Plot each of the paired emissions readings as a separate point on a graph where the vertical axis represents the value (pollutant concentration or volumetric flow, as appropriate) generated by the alternative monitoring system and the horizontal axis represents the value (pollutant concentration or volumetric flow, as appropriate) generated by the continuous emission monitoring system. On the graph, draw a horizontal line representing the mean value, $\bar{e}_p$, for the alternative monitoring system and a vertical line representing the mean value, $\bar{e}_v$, for the continuous emission monitoring system where,

$$\bar{e}_p = \frac{\Sigma e_p}{n} \qquad \text{(Eq. 9)}$$

and

$$\bar{e}_v = \frac{\Sigma e_v}{n} \qquad \text{(Eq. 10)}$$

where

e_p = Hourly value generated by the alternative monitoring system.

e_v = Hourly value generated by the continuous emission monitoring system.

n = Total number of hours for which data were generated for the tests.

A separate graph shall be produced for the data generated at each of the operating levels or fuel supplies described in paragraphs (a)(1)(iv) and (a)(1)(v) of this section.

(ii) Calculate the coefficient of correlation, r, between the emissions data from the alternative monitoring system and the continuous emission monitoring system using the following equation.

$$r = \frac{\Sigma e_p e_v - (\Sigma e_p)(\Sigma e_v)/n}{\{[\Sigma e_p^2 - (\Sigma e_p)^2/n][\Sigma e_v^2 - (\Sigma e_v)^2/n]\}^{1/2}} \qquad \text{(Eq. 11)}$$

(iii) If the calculated r-value is less than 0.8, the proposed method is unacceptable.

(c) The owner or operator shall include the following information in the application for approval and certification or recertification of an alternative monitoring system.

(1) Source identification information.

(2) A description of the alternative monitoring system.

(3) A description, results of the statistical tests for precision and bias, and data plots.

(4) Results of monitor reliability analysis.

(5) Results of monitor accessibility analysis.

(6) Results of monitor timeliness analysis.

(7) A detailed description of the process used to collect data, including location and method of ensuring an

accurate assessment of operating hourly conditions on a real-time basis.

(8) Results of tests and measurements (including the results of all reference method field test sheets, charts, laboratory analyses, example calculations, or other data as appropriate) necessary to substantiate that the alternative monitoring system is equivalent in performance to an appropriate, certified operating continuous emission monitoring system.

(d) The owner or operator shall develop and implement written operation, maintenance, and quality assurance procedures for the alternative monitoring system as required in appendix B of this part.

(e) The owner or operator shall submit information as requested by the Administrator to amend the permit to include any alternative monitoring system approved by the Administrator pursuant to this section.

§ 75.22 Recordkeeping requirements

(a) The owner or operator shall record hourly, with the exception of the measured percent sulfur in the fuel, the following information on unit operating time, load, and sulfur content range of fuel combusted for each affected unit, including units utilizing a common stack and electing to combine allowances and monitors. The owner or operator shall record every 6 hours the measured percent sulfur by weight in the fuel as-fired after the bunker (see Example Figure 1).

(1) The date and hour.

(2) Unit (boiler) operating time (hour or fraction of an hour recorded to nearest 15-min interval).

(3) Total heat input (mmBtu, rounded to four significant digits).

(4) Total integrated hourly gross unit load (rounded to nearest tenth of MWge).

(5) Operating load range (1–13) corresponding to total integrated gross load (see appendix C of this part).

(6) Sulfur content range (1–25) corresponding to the percent sulfur in fuel (see appendix C of this part).

(7) Percent sulfur by weight in fuel (rounded to nearest hundredth of a percent).

(b) The owner or operator shall record hourly the following information for SO^2 emissions, volumetric flow, moisture (if applicable), and NO_x emissions for each affected unit (see Example Figures 2 and 3).

(1) For SO^2 emissions,

(i) The date and hour.

(ii) Average hourly concentration (ppm).

(iii) Average hourly concentration adjusted for bias, if used (ppm).

(iv) For method of emissions determination, the owner or operator shall record one of the following codes to denote the source of the hourly emissions measurement or estimation method.

(A) 1—Primary certified pollutant concentration monitor.

(B) 2—Certified backup or portable pollutant concentration monitor.

(C) 3—Approved alternative monitoring system.

(D) 4—Reference Method (Method 6, 6A, 6B, or 6C).

(E) 5—Average of the hourly concentrations recorded by the monitor for the hour immediately before and the hour immediately following the missing data period.

(F) 6—90th percentile hourly concentration recorded by the monitor at the corresponding sulfur content range during the previous 30 days of operation.

(G) 7—90th percentile hourly concentration recorded by the monitor at the corresponding sulfur content range during the previous 365 days of operation.

(H) 8—Emissions estimate from Agency preapproved parametric monitoring system or correlation method for units with SO_2 emission controls.

(I) 9—Other data (specify method).

(v) Hourly mass emission rate (lb/hr) except as specified in paragraphs (b)(1)(vi) (A), (B), and (C) of this section.

(vi) Hourly mass emission rate (lb/hr) adjusted for bias, if used, except as specified in paragraphs (b)(1)(vi)(A), (B), and (C) of this section.

(A) For gas-fired or oil-fired units using the optional SO_2 emissions data protocol in Appendix D of this part, the owner or operator shall record the following information when the unit is combusting oil.

(1) Hourly flow of oil (gal/hr or lb/hr).

(2) Sulfur content of daily oil sample (rounded to nearest hundredth percent).

(3) Method of oil sampling (flow proportional, continuous drip, or manual).

(4) Hourly SO_2 mass emission rate (lb/hr).

(5) Average SO_2 mass emission rate (lb/hr) for each calendar quarter and year.

(6) Heat input from each shipment of natural gas, if any (mmBtu, rounded to four significant digits).

(B) For gas-fired units using the excepted method of daily manual oil sampling, the owner or operator shall record daily when the unit is combusting oil the highest sulfur content recorded from the most recent 30 daily oil samples.

(C) For units using alternative monitoring systems approved pursuant to § 75.21, the owner or operator shall record the hourly SO_2 mass emission rate (lb/hr) according to the approved procedures.

(2) For volumetric flow,

(i) The date and hour.

(ii) Average hourly volumetric flow (scfh).

(iii) Average hourly volumetric flow adjusted for bias, if used (scfh).

(iv) Average hourly stack moisture content, volume fraction, where SO_2 concentration measures are on a dry basis.

(v) For method of volumetric flow determination, the owner or operator shall record one of the following codes to denote the source of the hourly volumetric flow measurement or estimation method.

(A) 1—Primary flow monitor.

(B) 2—Backup flow monitor.

(C) 3—Approved alternative monitoring system.

(D) 4—Reference Method 2.

(E) 5—Average hourly flow rate recorded by the monitor at the corresponding unit load range during the previous 30 days of operation.

(F) 6—90th percentile hourly flow rates recorded by the monitor at the corresponding unit load range during the previous 30 days of operation.

(G) 7—90th percentile hourly flow rate recorded by the monitor at the corresponding unit load range during the previous 365 days of operation.

(H) 8—Other data (specify method).

(3) For NO_x emissions,

(i) The date and hour.

(ii) Average hourly concentration (ppm).

(iii) Average hourly emission rate (rounded to the nearest thousandth lb/mmBtu).

(iv) Average hourly emission rate adjusted for bias, if used (rounded to nearest thousandth lb/mmBtu).

(v) For method of emissions determination, the owner or operator shall record one of the following codes to denote the source of the hourly emission rate measurement or estimation method.

(A) 1—Primary continuous emission monitoring system.

(B) 2—Backup or portable continuous emission monitoring system.

(C) 3—Approved alternative monitoring system.

(D) 4—Reference Method (Method 7, 7A, 7B, 7C, 7D, or 7E).

(E) 5—Emissions estimate from Agency preapproved parametric monitoring system or correlation method

for units with post-combustion NO_x emission controls.

(F) 6—Average hourly emission rate recorded by the system at the corresponding unit load range during the previous 365 days of operation.

(G) 7—90th percentile hourly emission rate recorded by the system at the corresponding unit load range during the previous 30 days of operation.

(H) 8—90th percentile hourly emission rate recorded by the system at the corresponding unit load range during the previous 365 days of operation.

(I) 9—Other data (specify method).

(c) The owner or operator of an affected unit with SO_2 emission controls shall record hourly the following information on the operation and effectiveness of the SO_2 emission controls during periods when data from the SO_2 pollutant concentration monitor or an approved alternative monitoring system are not available (see Example Figure 4).

(1) The date and hour.

(2) Number of scrubber modules in operation.

(3) Percent solids in slurry (rounded to nearest tenth of a percent).

(4) Feed rate of makeup slurry to each scrubber module (gal/min).

(5) For wet flue gas desulfurization (scrubber) controls,

(i) Inline measure of absorber pH.

(ii) Average pressure differential across each scrubber module (inches of water column).

(6) For dry flue gas desulfurization (scrubber) controls,

(i) Dew point approach temperature for each module (°F).

(ii) Average pressure differential across each scrubber module (inches of water column).

(7) Estimate of percent SO_2 emissions reduction.

(d) The owner or operator of an affected unit with post-combustion NO_x emission controls shall record hourly the following information on the operation and effectiveness of the NO_x emission controls during periods when data from the continuous emission monitoring system or an approved alternative monitoring system are not available (see example Figure 5).

(1) The date and hour.

(2) Inlet air flow rate to the unit (scfh).

(3) Excess oxygen concentration of flue gas at stack outlet (rounded to nearest tenth of a percent).

(4) Carbon monoxide concentration of flue gas at stack outlet (ppm).

(5) Temperature of the flue gas at outlet of the unit (°F).

(6) Other parameters of the post-combustion NO_x emission controls specific to the emission reduction process.

(e) The owner or operator of an affected unit with a Phase I qualifying technology shall also record the following information.

(1) The date and hour.

(2) Average hourly inlet SO_2 concentration (ppm).

(3) Average hourly inlet SO_2 emission rate (rounded to nearest thousandth lb/mmBtu).

(4) Average hourly outlet SO_2 emission rate (rounded to nearest thousandth lb/mmBtu).

(5) During the initial 30-day test, daily values of the percent SO_2 emissions removal by the controls, percent SO_2 emissions removal from fuel pretreatment (if applicable), and the percent total SO_2 emissions removal.

(6) From the date of startup of the SO_2 emission controls through the fourth quarter of 1999, average quarterly and, for the fourth quarter, average annual values of the percent SO_2 emissions removal by the controls, the percent SO_2 emissions removal from fuel pretreatment (if applicable), and the percent total SO_2 emissions removal.

(7) For units using fuel pretreatment to achieve the 90-percent removal efficiency, all data from fuel analysis and company records on weight, sulfur content, and gross calorific value of the product and raw fuel lots.

(f) The owner or operator shall record the following information on a daily basis.

(1) For SO_2 pollutant concentration and diluent gas monitors and NO_x continuous emission monitoring systems,

(i) Percent monitor availability during the previous 365 calendar days (rounded to nearest hundredth of a percent).

(ii) Results of daily calibration error tests (percent error, rounded to nearest tenth of a percent) and number of out-of-control hours.

(iii) Bias adjustment factor for SO_2 pollutant concentration monitor (rounded to nearest tenth, 1.0 if no adjustment factor necessary).

(iv) Bias adjustment factor for NO_x continuous emission monitoring system (rounded to nearest tenth, 1.0 if no adjustment factor necessary).

(2) For flow monitors,

(i) Percent monitor availability during previous 365 calendar days (rounded to nearest hundredth of a percent).

(ii) Results of daily calibration error tests (percent error, rounded to nearest tenth of a percent) or electronic drift tests (percent span drift, rounded to nearest tenth of a percent) and number of out-of-control hours.

(iii) Bias adjustment factor for flow monitor (rounded to nearest tenth, 1.0 if no adjustment factor necessary).

(3) Total daily calculated tons of SO_2 (rounded to nearest thousandth of a ton).

(4) F-factor value(s) used to convert NO_x pollutant concentration to emission rate in lb/mmBtu.

(5) Daily CO_2 mass emissions discharged to the atmosphere (lb).

(g) The owner or operator shall record hourly the average stack gas temperature (°F), the average gas exit velocity (rounded to nearest tenth fps), and the average diluent (O_2 or CO_2) concentration (rounded to nearest tenth of a percent) used to calculate NO_x emission rate in lb/mmBtu.

(h) The owner or operator shall maintain records on adjustments and maintenance performed on pollutant concentration and diluent gas monitors, flow monitors, opacity monitors, and moisture monitors (if applicable), including corrective actions.

(i) Each owner or operator shall maintain a file of all measurements, reports, and other information required by this part at the source in a form suitable for inspection for at least 5 years. This file shall contain the following information and data.

(1) The information and data required in paragraphs (a)–(h) of this section.

(2) Records of all calibrations and recalibrations for the continuous emission monitoring system and the continuous opacity monitoring system.

(3) Records of all initial, quarterly, semiannual, and annual tests for the continuous emission monitoring system and records of all initial, quarterly, and annual tests required for the continuous opacity monitoring system.

(4) The results of all trial runs and certification tests and quality assurance activities and measurements (including all reference method field test sheets, charts, records of combined system responses, laboratory analyses, and example calculations) necessary to substantiate that all continuous emission monitoring systems and components meet the equipment and performance specifications in appendix A of this part and that the continuous opacity monitoring system meets the requirements of Performance Specification 1 in 40 CFR part 60, appendix B.

(5) A copy of the quality control plan as described in appendix B of this part.

(6) A copy of the source code (if available) used to process the continuous emission monitoring system or component data and to calculate substitute data for missing data periods.

§ 75.23 **Reporting requirements.**

(a) *Monitoring plan.* Each designated representative of an affected unit shall submit Form 7510, Monitoring Plan, including continuous emission monitoring system information, as part of the permit application required by 40 CFR part 72. For Phase I affected units, the plan shall be submitted no later than the date of submission of the permit application. For Phase II affected-units, the monitoring plan shall be submitted no later than the request for certification as required by § 75.18. The following information shall be reported using this form and if applicable, Supplementary Form 7512, Monitoring Plan for Common Stacks (see Figures 6 and 7).

(1) Acid Rain Program unit identification numbers(s), including the identification of all units utilizing a common stack and electing to combine allowances and monitors as provided for in § 75.11(a), the short name of each unit, and the name and address of the contact person for the continuous emission monitoring system.

(2) Description of monitor location, including scale diagrams and other documentation that the monitor location meets the appropriate siting criteria.

(3) Type of boiler or boilers for units utilizing a common stack and fuel(s) combusted.

(4) Type(s) of emission controls for SO_2, NO_x, and particulates installed or to be installed, including specifications of whether such controls are post-combustion, pre-combustion, or integral to the combustion process.

(5) Identification and description of all monitoring components in the continuous emission monitoring system (i.e., SO_2 pollutant concentration monitor, flow monitor, moisture monitor, if applicable; NO_x pollutant concentration monitor and diluent gas monitor) and the continuous opacity monitoring system, including:

(i) Manufacturer and model number.

(ii) Actual or projected installation date (month and year).

(iii) A brief description of the component type or method of operation (e.g., in situ pollutant concentration monitor or ultrasonic flow monitor).

(6) Identification and description of all major hardware and software components of the data acquisition and handling system, including:

(i) For hardware components, the manufacturer, model number, and actual or projected installation date.

(ii) For software components, identification of the provider, whether the software is customized or off-the-shelf, a brief description of customized features, and availability of source code on-site.

(iii) A data flow diagram and a listing of computer algorithms used to calculate the recorded emissions and volumetric flow values.

(7) For gas-fired units and oil-fired units that intend to use the optional procedures in Appendix D of this part for monitoring SO_2 emissions, a description of the fuel flowmeter and data supporting its relative accuracy.

(b) *Certification tests.* The owner or operator of an affected unit shall provide notification and a report of the results of initial certification tests and any recertification tests as follows.

(1) The owner or operator shall provide notification to the Administrator of the dates upon which initial certification tests or recertification tests for the continuous emission monitoring system will be conducted. Notification shall be postmarked not less than 30 days prior to the test. For initial certification or recertification tests for the continuous opacity monitoring systems, notification shall be submitted to the applicable permitting authority. If notification substantially similar to that above is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy this notification requirement, provided the Acid Rain Program unit identification number(s) is denoted.

(2) The owner or operator shall furnish the Administrator (with copies to the applicable Regional Administrator and the applicable State air pollution control agency), a written report of the results of the performance tests for certification or recertification of the continuous emission monitoring system.

(3) The owner or operator shall submit the initial certification test results prior to the date the continuous emission monitoring system must be installed, operational, and certified.

(4) Each certification or recertification report shall include the following information.

(i) Name of utility and plant, address, contact person, and phone number.

(ii) Applicable plant and point identification numbers, unit number(s), identification of units sharing a common stack and electing to combine allowances and monitors as provided under § 75.11(a), and type of boiler and fuel(s) combusted.

(iii) Stack inside diameter (in feet) at the monitor location.

(iv) Stack height (in feet).

(v) A brief description of the continuous emission monitoring system installed to meet the requirements of this part, including the following information for each pollutant concentration, diluent gas, or flow monitor.

(A) Manufacturer.

(B) Serial number.

(C) Model number.

(D) Monitor type (e.g., in situ, extractive, dilution).

(E) Monitor location.

(vi) The results of each certification test for the continuous emission monitoring system in appendix A of this part, including the type of test conducted and the date.

(vii) A brief description of the continuous opacity monitoring system installed to meet the requirements of this part.

(viii) The results of each certification test for the continuous opacity monitoring system required by § 75.19 and described in Performance Specification 1 of 40 CFR part 60, appendix B, including the type of test conducted and the date.

(ix) Verification of the accuracy of emissions and volumetric flow calculations performed by the data acquisition and handling system, including a summary of equations used to convert component data to units of the standard and to calculate substitute data for missing data periods, including sample calculations.

(c) *Quarterly reports.* The designated representative shall electronically report the following data and information to the Administrator quarterly, beginning with the quarter during which the continuous emission monitoring system is initially certified. Each electronic report must be received at the address given in § 75.4(a) by the 30th day of the month following the end of each calendar quarter.

(1) The information and data required in paragraphs (a)–(f) of § 75.22.

(2) Tons of SO_2 emitted during the quarter and cumulative SO_2 emissions for calendar year.

(3) Average NO_x emission rate (lb/mmBtu) during the quarter and cumulative NO_x emission rate for calendar year.

(4) Tons of CO_2 emitted during quarter and cumulative CO_2 emissions for calendar year.

(5) Total heat input (mmBtu) and integrated gross unit load (MWge) for quarter and cumulative heat input and integrated gross unit load for calendar year.

(d) *Electronic report format.* Each quarterly report shall be submitted electronically to the Administrator as an ASCII flat file via either an IBM-compatible personal computer floppy diskette or by a modem.

(e) *Quality assurance and quality control test reports.* The owner or operator shall report, on a quarterly

basis, the results of quarterly, semiannual, and annual quality assurance and quality control tests for the continuous emission monitoring system and the continuous opacity monitoring system required by appendix B of this part, beginning with the quarter following initial certification of either system.

(1) Each report shall contain, at a minimum, information on the type(s) of tests conducted, the date, individual test run data on supporting data sheets, and the results of any bias test indicating low bias in the monitoring system or component and the bias adjustment factor from Equation 7–6 in appendix A of this part. The owner or operator also shall report the results of all relative accuracy test audits performed during the quarter including those performed for the purpose of achieving the results required to qualify for less frequent relative accuracy test audits and/or eliminating or reducing a bias adjustment factor.

(2) Each report must be received at the address given in § 74.4(a) by the 30th day of the month following the end of each calendar quarter. Quality assurance and quality control test run data and statistics must be reported electronically to the Administrator as an ASCII flat file via either an IBM-compatible personal computer floppy diskette or by a modem. Test reports, supporting calculations, and explanatory material may be submitted in hard copy form.

(f) *Phase I qualifying technology reports.* The designated representative of an affected unit equipped with a Phase I qualifying technology should electronically report the information and data required in paragraphs (e) (1) through (5) of § 75.22 for the initial 30-day test to the Administrator by the 30th day of the month following the end of the test. The designated representative shall also electronically report the information and data required in paragraphs (e)(1) through (4) and (6) of § 75.22 to the Administrator on a quarterly basis, beginning with the startup of the SO_2 emission controls through the fourth quarter of 1999. Each report shall also contain all measurements and calculations necessary to substantiate that the qualifying technology achieves the required percent reduction in SO_2 emissions.

(g) *Opacity reports.* The owner or operator shall report excess emissions of opacity to the applicable permitting authority.

(h) *Alternative flow monitor location demonstration reports.* In cases where no location exists in the existing ducts or stack that will satisfy the siting criteria specified in § 75.13(a)(3) and in appendix A of this part, the owner or operator may petition the Administrator for an alternative monitoring location or alternative method for monitoring flow. The demonstration report must be received, for Phase I affected units, no later than prior to the date of submission of the permit application and, for Phase II affected units, no later than the request for certification as required by § 75.18. The demonstration report shall, at a minimum, contain the following information.

(1) Identification of the affected unit(s).

(2) Description of why the minimum siting criteria cannot be met within the existing ductwork or stack(s). This description shall include diagrams of the existing ductwork and stack(s) as well as documentation of any attempts to locate a flow monitor.

(3) Description of proposed alternative monitoring location or alternative method for monitoring flow.

(i) *Retiring units.* The owner or operator shall submit a statement, certified by the owner or operator and the designated representative, of the commitment to permanently retire an affected unit prior to January 1, 1995.

(1) The owner or operator shall certify the limited life of the unit prior to the date by which the continuous emission monitoring system must be installed.

(2) In no case may the notification be submitted after December 31, 1994.

§ 75.24 [Reserved]

Appendix A to Part 75—Specifications and Test Procedures

1. SO_2 Pollutant Concentration Monitors and NO_x Continuous Emission Monitoring Systems

1.1 Installation and Measurement Location. Following the procedures in section 3.1, 40 CFR part 60, Appendix B, Performance Specification 2, install the monitor or monitoring system at an accessible location where the pollutant concentration and emission rate measurements are directly representative of the total emissions from the affected unit. Select a representative measurement point or path for the monitor probe(s) such that the SO_2 pollutant concentration monitor or NO_x continuous emission monitoring system (NO_x pollutant concentration monitor and diluent gas monitor) will pass the relative accuracy test (see Section 6). If the cause of failure to meet the relative accuracy tests is determined to be the measurement location, the monitor probe(s) must be relocated.

1.1.2 *Point Pollutant Concentration or Diluent Gas Monitors.* The measurement point shall be (1) within or centrally located within the centroidal area of the stack or duct cross section, or (2) no less than 1.0 meter from the stack or duct wall.

1.1.3 *Path Pollutant Concentration or Diluent Gas Monitors.* The measurement path shall (1) be totally within the inner area bounded by a line 1.0 meter from the stack or duct wall or (2) have at least 70.0 percent of the path within the inner 50.0 percent of the stack or duct cross-sectional area, or (3) be centrally located within any part of the centroidal area.

1.2 Equipment Specifications. Each pollutant concentration or diluent gas monitor shall be designed and equipped with a calibration gas injection port that allows a check of the entire measurement system when calibration gases are introduced. The parts of the measurement system that shall be included, as applicable, are sample lines, filters, scrubbers, conditioners, data recorder, as much of the probe as practicable, and all other monitor components exposed to the sample gas during normal sampling. If the pollutant concentration monitor is an extractive type, the injection port shall be at a point no closer to the analyzer than the back of the probe. If dilution-type systems are used, the injection port shall be placed prior to any dilution. Daily calibration error checks shall be made by charging the pollutant concentration or diluent gas monitor with calibration gases through this injection port.

Each pollutant concentration or diluent gas monitor shall be designed to allow daily determinations of calibration error (positive or negative) at the low-level and high-level concentrations specified in section 2.1, appendix B, of this part.

1.2.1 *Instrument Span.* Select spans for pollutant concentration and diluent gas monitors so that they include all expected emission rates and concentrations. The average concentration shall be between 40.0 and 75.0 percent of span. Whenever the monthly average concentration of the emissions being monitored falls below 40.0 percent or rises above 75.0 percent of span, adjust the span so that the emission measurements fall within the cited boundaries. Full-scale exceedances shall not occur. Use dual-range analyzers to accommodate a wide range of expected concentrations.

1.3 Performance Specifications.

1.3.1 *Calibration Error.* The calibration error of pollutant concentration monitors shall not deviate from the reference value of the calibration gas by more than 2.5 percent. This specification does not apply when the average concentration is 250 ppm or less. When the average concentration is equal to or less than 250 ppm, the calibration error shall not deviate from the reference value of the calibration gas cylinder by more than 5.0 percent or 8 ppm, whichever is greater.

The calibration error of diluent gas monitors shall not deviate from the reference value of the calibration gas by more than 0.5 percent. If the continuous emission monitoring system includes pollutant concentration and diluent gas monitors, calibration errors shall be determined separately for the pollutant concentration monitor and the diluent gas monitor.

1.3.2 *Relative Accuracy for SO_2.* The relative accuracy for SO_2 pollutant concentration monitors shall not exceed 10.0 percent. This specification does not apply to affected units where the average of the monitor measurements of SO_2 concentration during the relative accuracy test audit is less than or equal to 250.0 ppm. For these affected units, the mean value of the monitor measurements shall be within $\pm$15.0 ppm of the reference method mean value.

1.3.3 *Relative Accuracy for NO_x.* The relative accuracy for NO_x continuous emission monitoring systems shall not exceed 10.0 percent. This specification does not apply to affected units where the average of the monitoring system measurements of NO_x emission rate during the relative accuracy test audit is less than or equal to 0.50 lb/mmBtu. For these affected units, the mean value of the NO_x continuous emission monitoring system measurements shall be within $\pm$0.05 lb/mmBtu of the reference method mean value.

1.3.4 *Relative Accuracy for Diluent.* The relative accuracy for diluent gas monitors shall not exceed 10.0 percent of the reference method mean value or 1.0 percent O_2 or CO_2, whichever is greater.

1.3.5 *Bias.* SO_2 pollutant concentration monitors and NO_x continuous emission monitoring systems shall not exhibit low bias as determined by the test procedure in section 7.5. The bias specification applies to all SO_2 pollutant concentration monitors, including those where the average SO_2 concentration is 250.0 ppm or less, and to all NO_x continuous emission monitoring systems, including those where the average emission rate is 0.50 lb/mmBtu or less.

1.3.6 *Cycle Time/Response Time.* The cycle time/response time for pollutant concentration monitors, diluent gas monitors, and NO_x continuous emission monitoring systems shall not exceed 15 min.

2. Flow Monitors

2.1 Installation and Measurement Location. Install the flow monitor in a location that provides representative volumetric flow over all operating conditions. Such a location is one that provides an average velocity of the flue gas flow over the stack or duct cross section, provides a representative SO_2 emission rate (in lb/hr), and is representative of the pollutant concentration monitor location. For volumetric flow measurements where cyclonic or swirling flow conditions exist, use the procedures in section 2.4 of Method 1 to establish a proper location for the flow monitor. Where the moisture content of the flue gas effects volumetric flow measurements, use the procedures in both Reference Methods 1 and 4 of 40 CFR part 60, appendix A, to establish a proper location for the flow monitor. Flow monitor locations should be selected to minimize the effects of condensation, coating, erosion, or other conditions that could adversely affect flow monitor performance.

The installation of a flow monitor is acceptable if the location satisfies the minimum siting criteria of Method 1 in 40 CFR part 60, appendix A (i.e., the location is greater than or equal to two stack or duct diameters downstream or one-half diameter upstream from a flow disturbance), and the flow monitor satisfies the performance specifications of this part. If the flow monitor is installed in a location that does not satisfy these physical criteria, but nevertheless the monitor achieves the performance specifications of this part, then the Administrator may certify the location as acceptable. Whenever it is physically impossible to install a flow monitor at any location that satisfies these physical siting criteria in either the stack or breeching ducts serving any unit or combination of units, the owner or operator may petition the Administrator for an alternative monitoring location or alternative method for monitoring flow.

Whenever the flow monitor is installed in a location that is greater than or equal to two stack or duct diameters downstream or one-half diameter upstream from a flow disturbance, but nevertheless the monitor does not achieve the performance specifications of this part, the owner or operator shall utilize the alternative procedures described in section 2.5 of Method 1 to make accurate flow rate determinations. Whenever the owner or operator successfully demonstrates that such modifications are necessary, the Administrator may approve an interim alternative flow monitoring methodology and an extension to the required certification date for the flow monitor.

2.2 Equipment Specifications. All flow monitor designs shall provide for at least quarterly transducer checks. Flow monitor designs shall meet the applicable performance specifications in section 2.3. All flow monitors shall either be designed for daily multipoint calibration or the owner or operator must perform quarterly relative accuracy test audits as specified in appendix B of this part. If the flow monitor is designed for daily calibration, the monitor shall be equipped with a calibration system that allows a check once every 24 hours (or more frequently) of the entire measurement system from the probe tip through the data acquisition and handling system at two gas flows: (1) The normal operating rate, and (2) 90 percent or more of the maximum operating rate.

2.2.1 *Instrument Span.* Select the span of the flow monitor such that it includes all expected volumetric flow rates. The average volumetric flow shall be between 40.0 and 75.0 percent of span. Whenever the monthly average volumetric flow falls below 40.0 percent or rises above 75.0 percent of span, adjust the span so that the monthly average volumetric flow is within the cited ranges.

2.2.2 *Interference Checks.* Ultrasonic and differential pressure flow monitors shall provide an automatic timed periodic back purging (simultaneously on both sides of the probe) or equivalent method of sufficient force and frequency to keep the transceiver surface/sample port, and the probe and lines, respectively, free of obstructions. Self-averaging differential pressure flow monitors shall provide an automatic drain for wet gases. All flow monitors shall provide a method or mechanism (manual check is acceptable) for zeroing and calibrating the transducer. Differential pressure flow monitors shall provide a method or mechanism for detecting leaks or pluggage in the system. Thermal flow monitors shall provide a method or mechanism for ensuring the probe remains clean.

2.3 Performance Specifications.

2.3.1 *Calibration Error.* The calibration error of flow monitors that perform daily calibration error tests shall not deviate from the reference value by more than 3.0 percent.

2.3.2 *Electronic Drift.* The electronic drift of flow monitors that do not perform daily calibration error tests shall not deviate from the reference value of the input signal by more than 3.0 percent.

2.3.3 *Relative Accuracy.* The relative accuracy for flow monitors, where volumetric gas flow is measured in scfh, shall not exceed 15.0 percent through December 31, 1999. Beginning on January 1, 2000, the relative accuracy of flow monitors on both Phase I and Phase II affected units shall not exceed 10.0 percent. These specifications do not apply to affected units where the average of the flow monitor measurements of gas velocity during the relative accuracy test audit is less than or equal to 10.0 feet per second (fps). For these affected units, the mean value of the flow monitor measurements shall be within $\pm$1.0 fps of the reference method mean value.

2.3.4 *Bias.* Flow monitors shall not exhibit low bias as determined by the test procedure in section 7.5. The bias specification applies to all flow monitors including those where the average gas velocity is 10.0 fps or less.

2.3.5 *Orientation Sensitivity.* For velocity measurement systems that use the flow direction of the gas, such as differential pressure flow monitors, no measurement shall exceed $\pm$4.0 percent of the zero-degree orientation value.

3. Combined SO_2-Flow Monitoring Systems

3.1 Relative Accuracy. Beginning on January 1, 2000, the relative accuracy for combined SO_2-flow monitoring systems for determining SO_2 emissions in lb/hr shall not exceed 10.0 percent. This specification applies to both Phase I and Phase II affected units, except those units where the average SO_2 concentration is less than or equal to 250.0 ppm or the average gas velocity is less than or equal to 10.0 fps during the relative accuracy test audit.

3.2 Cycle Time. Combined SO_2-flow monitoring systems shall complete a minimum of one cycle of operation (sampling, analyzing, and recording) for each successive 15-min. interval.

3.3 Bias. Combined SO_2-flow monitoring systems shall not exhibit low bias as determined by the test procedure in section 7.5.

4. Data Acquisition and Handling Systems

Automated data acquisition and handling systems shall: (1) read and record the full range of pollutant concentrations and volumetric flow from zero through span; and (2) provide a continuous, permanent record of all measurements and required information as an ASCII flat file capable of transmission via an IBM-compatible personal computer diskette or other electronic media. These systems also shall have the capability of

interpreting and converting the individual output signals from an SO_2 pollutant concentration monitor, a flow monitor, and a NO_x continuous emissions monitoring system to produce a continuous readout of pollutant mass emission rates in the units of the standard. Where CO_2 emissions are measured with a continuous emission monitoring system, the data acquisition and handling system shall also produce a readout of CO_2 mass emission rates in the appropriate units of the standard.

Data acquisition and handling systems shall compute and record monitor calibration errors; any bias adjustments to pollutant concentration, flow rate, or NOx emission rate data; and all missing data procedure statistics specified in § 75.12 through § 75.14.

5. Calibration Gas

5.1 Reference Values. Calibration gases shall include the following.

5.1.1 *Standard Reference Materials.* These calibration gases may be obtained from the National Institute of Standards and Technology (NIST) at the following address: Quince Orchard and Cloppers Road, Gaithersburg, Maryland 20899.

5.1.2 *EPA Traceability Protocol 1 Gases.* Protocol 1 gases must be vendor-certified to be within 2.0 percent of the concentration specified on the cylinder label.

5.1.3 *NIST/EPA-approved Certified Reference Materials.*

5.2 Concentrations. Three concentration levels are required as follows.

5.2.1 Low-level Concentration. Zero to 20 percent of span.

5.2.2 *Mid-level Concentration.* 40 to 60 percent of span.

5.2.3 *High-level Concentration.* 80 to 100 percent of span.

6. Certification Tests and Procedures

6.1 Pretest Preparation. Install the components of the overall continuous emission monitoring system (i.e., pollutant concentration monitors, diluent gas monitor, and flow monitor) as specified in sections 1, 2, and 3 above, and prepare each system component and the combined system for operation in accordance with the manufacturer's written instructions.

6.2 Calibration Error Test. With the unit operating at greater than or equal to 50 percent of maximum load, measure the calibration error of each pollutant concentration monitor, diluent gas monitor, and flow monitor that performs daily calibration error tests once a day (at 24-hr intervals) for 7 consecutive days according to the following procedures.

If periodic automatic or manual adjustments are made to the monitor zero and calibration settings, conduct the calibration error test immediately before these adjustments, or conduct it in a way that the magnitude of the calibration error can be determined and recorded.

Introduce the calibration gas at the probe. Conduct the calibration error test for pollutant concentration monitors and diluent gas monitors at the following concentrations: (1) low-level—zero to 20 percent of span, (2) mid-level—40 to 60 percent of span, and (3) high-level—80 to 100 percent of span. Challenge the pollutant concentration monitor three times with each reference gas, but not in succession. Record the monitor response (see example data sheet in Figure 1). For each concentration, use the average of the three responses to determine the calibration error using Equation 7.1.

For flow monitors that perform daily calibration error tests, introduce reference signals to the flow sensor at the following gas flow rates: (1) Low-level—the minimum safe and stable operating level, and (2) high-level—the maximum normal operating level. Record the response to each reference signal and calculate the percent difference using Equation 7–1.

Calibration error test results are acceptable for monitor certification if none of the values for the 7-day period exceed the calibration error specifications in sections 1.3 and 2.3.

6.3 Electronic Drift Test. For flow monitors that do not perform daily calibration error tests, determine the electronic drift of the flow monitor once every 24 hours for 7 consecutive days according to the following procedures.

Introduce, or activate internally, electronic reference signals to the flow sensor at the following levels: (1) Low-level—zero to 20 percent of span and (2) high-level—80 to 100 percent of span. Record the response to each reference signal and calculate the percent difference using Equation 7–1.

Electronic drift test results are acceptable for flow monitor certification if none of the values for the 7-day period exceed the electronic drift specification in section 2.3.

6.4 Orientation Sensitivity Test. For velocity measurement systems that use the flow direction of the gas, such as differential pressure flow monitors, perform an orientation sensitivity test to ensure proper alignment of the monitor with respect to the axial component of the flue gas flow. While the unit (or units, if more than one unit exhausts into the stack or duct) is combusting primary fuel, perform the test according to the following procedures at three gas flow rates: (1) The minimum safe and stable operating level, (2) 90.0 percent or greater of the maximum operating level, and (3) at the normal operating level or an evenly spaced intermediary flow velocity if the normal operating level is within 10.0 percent of (1) or (2) above. The flow monitor shall be continuously measuring gas velocity at all times. During the period of relatively steady-state gas flow, rotate the measurement sensor 10.0 degrees on each side of the direction of flow in increments of 5.0 degrees. Perform this test three times at each operating level. Orientation sensitivity test results are acceptable for monitor certification if none of the flow measurements exceed ±4.0 percent of the zero-degree orientation value.

6.5 Cycle Time/Response Time Test. Perform cycle time/response time tests for each pollutant concentration monitor, diluent gas monitor, and NO_x continuous emission monitoring system according to the following procedures. While the monitor or monitoring system is measuring and recording the concentration or emission rate, alternately inject low-level concentration and high-level concentration calibration gases into the injection port until a stable response is reached. Record the amount of time required for the monitor or monitoring system to complete 95.0 percent of the concentration or emission rate stepchange. For monitors or monitoring systems that perform a series of operations (purge, sample analyze, etc.), time the injections of the calibration gases so they will produce the longest possible response time.

Cycle time/response time test results are acceptable for monitor or monitoring system certification if none of the response times exceed 15 min. Beginning on January 1, 2000, a cycle time/response time test will be required for each combined SO_2-flow monitoring system. The response time of the combined system shall not exceed 15 min.

6.6 Relative Accuracy and Bias Tests. Perform relative accuracy test audits for each SO_2 pollutant concentration monitor, flow monitor, and NO_x continuous emission monitoring system, and, beginning January 1, 2000, for each combined SO_2-flow monitoring system. Data from the relative accuracy test audits shall be used to calculate bias as well as relative accuracy.

Each day during which a relative accuracy test audit is being performed, conduct and record the results of a calibration error test (or electronic drift test for flow monitors that cannot perform daily calibration error tests) prior to any audit runs. Each relative accuracy test audit must be completed within a 7-day period. No adjustments or repairs to the monitor or monitoring system other than routine calibration error checks shall be performed during relative accuracy test audits. Modifications to the SO_2 pollutant concentration monitor, flow monitor, and the NO_x continuous emission monitoring system, e.g., changing the sampling frequency, changing cleaning frequencies, or modifying time-shared systems, are prohibited during the test audits.

Perform relative accuracy test audits for each SO_2 pollutant concentration monitor or NO_x continuous emission monitoring systems at a single unit operating level greater than or equal to 50.0 percent of maximum steam capacity while the unit (or units, if more than one unit exhausts into the stack or duct) is combusting primary fuel.

Perform relative accuracy test audits for each flow monitor at each of three gas flow rates (or unit operating levels): (1) The minimum safe and stable operating level, (2) 90.0 percent or greater of maximum operating level, and (3) at the normal operating level or an evenly spaced intermediary flow velocity if the normal operating level is within 10.0 percent of (1) or (2) above. These test audits shall be performed while the unit (or units, if more than one unit exhausts into the stack or duct) is combusting primary fuel and must be completed within a 7-day period.

Beginning January 1, 2000, perform relative accuracy test audits for each combined SO_2-flow monitoring system at each of three gas flow rates (or unit operating levels): (1) The minimum safe and stable operating level, (2) 90.0 percent or greater of the maximum operating level, and (3) at the normal operating level or an evenly spaced intermediary flow velocity if the normal operating level is within 10.0 percent of (1) or (2) above. These combined system test audits

shall be performed concurrently with the test audits for the SO_2 pollutant concentration monitor and the flow monitor while the unit (or units, if more than one unit exhausts into the stack or duct) is combusting primary fuel. The test audits must be completed within a 7-day period.

6.6.1 *Reference Method Measurement Location.* Select a location for reference method measurements that is (1) accessible; (2) at least two equivalent diameters downstream from the nearest emission control, the point of pollutant generation, or other point at which a change in the pollutant concentration or flow rate may occur; and (3) at least a half equivalent diameter upstream from any flow disturbance, such as the discharge to the atmosphere or emission control. The reference method measurement location shall be in the same proximity as the monitor or monitoring system location. The reference method measurement location must meet the requirements of Method 1 in 40 CFR part 60, appendix A, for volumetric flow, or Performance Specification 2 in 40 CFR part 60, appendix B, for SO_2 and NO_x continuous emission monitoring systems, as appropriate, unless otherwise approved by the Administrator.

6.6.2 *Traverse Point Selection.* Select traverse points that ensure acquisition of representative samples of pollutant concentration, emission rate, and flue gas flow rate over the stack or duct cross section according to the following procedures. Establish a "measurement line" that passes through the centroidal area and in the direction of any expected concentration or flow stratification. If this line interferes with the monitor or monitoring system measurements, displace the line up to 30.0 cm (or 5.0 percent of the equivalent diameter of the cross section, whichever is less) from the centroidal area. Locate three traverse points at 16.7, 50.0, and 83.3 percent of the measurement line. If the measurement line is longer than 2.4 m and concentration or flow rate stratification is not expected, the tester may choose to locate the three traverse points on the line at 0.4, 1.2, and 2.0 m from the stack or duct wall. The tester may select other traverse points provided that they can be shown, to the satisfaction of the Administrator, to provide a representative sample over the stack or duct cross section. Conduct all reference method tests within 3.0 cm of the traverse points, but not less than 3.0 cm from the stack or duct wall.

6.6.3 *Sampling Strategy.* Conduct the reference method tests so they will yield results representative of the pollutant concentration, emission rate, and flue gas flow rate from the unit and can be correlated with the pollutant concentration monitor, diluent gas monitor, flow monitor, NO_x continuous emission monitoring system, and combined SO_2-flow monitoring system measurements. Although it is preferable to conduct the diluent (O_2 or CO_2) measurements and any moisture measurements that may be needed simultaneously with the pollutant concentration and flue gas flow rate measurements, diluent and moisture measurements taken within 30-min to 60-min of these measurements will be acceptable for estimating pollutant mass emission rate relative to the heat input of the fuel (lb/mmBtu) or pollutant mass emissions per unit time (lb/hr). In order to properly correlate individual NO_x continuous emission monitoring system, volumetric flow rate, and combined SO_2-flow monitoring system data with the reference method data, mark the beginning and end of each reference method test run (including the exact time of day) on the individual chart recorder(s) or other permanent recording device(s) for the pollutant mass emission rate.

Use the following sampling strategies for the reference method tests.

For integrated samples, e.g., Method 6 and Method 4, make a sample traverse of at least 21 min, sampling for 7 min at each traverse point.

For grab samples, e.g., Method 7, take one sample at each traverse point, scheduling the grab samples so that they are taken simultaneously (within a 3-min period) or are spaced in equal intervals of time over a 21-min (or less) period. A test run for grab samples must contain at least three separate measurements.

When testing the relative accuracy of a combined SO_2- flow monitoring system, perform a Method 2 run simultaneously with each SO_2 pollutant concentration reference method test run. Also perform a moisture determination analysis (if needed) using Method 4. The Method 2 velocity traverse points shall be sampled for equal lengths of time and at evenly spaced intervals over the duration of the pollutant concentration sample run.

6.6.4 *Correlation of Reference Method and Continuous Emission Monitoring System, Flow Rate, and Combined Emission Rates.* Confirm that the monitor or monitoring system and reference method test results are on consistent moisture, pressure, temperature, flow, and diluent concentration bases (e.g., since the flow monitor measures flow rate on a wet basis, Method 2 test results must also be on a wet basis). Also, consider the response times of the pollutant concentration monitor, the continuous emission monitoring system, and the flow monitoring system to ensure comparison of simultaneous measurements.

For each relative accuracy test audit run, compare the measurements obtained from the monitor or continuous emission monitoring system (in ppm, percent CO_2 or O_2, lb/hr, lb/mmBtu, or other units) against the corresponding reference method values. Tabulate the paired data in a table such as the one shown in Figure 2.

6.6.5 *Number of Reference Method Tests.* A minimum of nine sets of paired monitor (or monitoring system) and reference method test data shall be performed for every required (i.e., certification, quarterly, semiannual, or annual) relative accuracy or bias test audit. For the certification and periodic quality assurance relative accuracy or bias test audits for flow monitors and combined SO_2-flow monitoring systems, a minimum of nine sets shall be performed at each of the three gas flow rates specified in section 6.6. Conduct each set within a period of 30 to 60 min. The data set used for the relative accuracy calculation shall also be used for the bias calculation.

Note: The tester may choose to perform more than nine sets of reference methoa tests. If this option is chosen, the tester may, at his or her discretion, reject a maximum of three sets of the test results as long as the total number of test results used to determine the relative accuracy or bias is greater than or equal to nine. The tester must report all data including the rejected data. All reference method test results including those in preparatory or practice trials shall be reported.

6.6.6 *Reference Methods.* Methods 2; 3 or 3A; 4; 6, 6A, 6B, or 6C; and 7, 7A, 7B, 7C, 7D, or 7E from appendix A of 40 CFR part 60 or their approved alternatives are the reference methods for velocity, diluent gas (O_2 and CO_2), moisture, SO_2, and NO_x, respectively.

7. Calculations.

7.1 Calibration Error. Analyze the calibration error data for pollutant concentration monitors, diluent gas monitors, and flow monitors that perform calibration error tests as follows. Calculate the calibration error as a percentage of the reference value at the low-level, mid-level, and high-level concentrations or reference signals specified in Sections 6.2 and 6.3. Perform this calculation each day during the 7-day certification test. Use the following equation to calculate calibration error.

$$CE = \frac{R-A}{R} \times 100 \qquad \text{(Eq. 7-1)}$$

where:

CE = Calibration error, as a percentage of the reference value.

R = Low-, mid-, or high-level calibration gas or reference signal introduced into the monitor, monitoring system, or flow sensor analyzer (ppm or other appropriate units). (If the low-level calibration gas or reference signal is zero, use 8.0 ppm or other appropriate units).

A = Average of the three monitor, monitoring system, or analyzer responses to the calibration gas or reference signal (ppm or other appropriate units).

7.2 Electronic Drift. Analyze the electronic drift data for flow monitors that do not perform daily calibration error tests as follows. Calculate the electronic drift as a percentage of the reference value at the low-level, mid- level, and high-level reference signals specified in Section 6.3 using Equation 7-1. Perform this calculation each day during the 7-day certification test.

7.3 Relative Accuracy for SO_2 Pollutant Concentration Monitors, Diluent Gas Monitors, and Flow Monitors. Analyze the relative accuracy test audit data from the reference method tests for SO_2 pollutant concentration monitors, diluent gas monitors, and flow monitors using the following procedures. Summarize the results on a data sheet. An example is shown in Figure 2. Calculate the mean of the monitor or monitoring system measurement values.

Calculate the mean of the reference method values. Using data from the automated data acquisition and handling system, calculate the arithmetic differences between the reference method and monitor measurement data sets. Then calculate the arithmetic mean of the difference, the standard deviation, the confidence coefficient, and the monitor relative accuracy using the following procedures and equations.

7.3.1 Arithmetic Mean. Calculate the arithmetic mean of the difference, $\bar{d}$, of a data set as follows.

$$\bar{d} = \frac{1}{n} \sum_{i=1}^{n} d_i \qquad \text{(Eq. 7-2)}$$

where:

n = Number of data points

$$\sum_{i=1}^{n}$$

d_i = Algebraic sum of the individual differences d_i.

d_i = The difference between a reference method value and the corresponding continuous emission monitoring system value ($RM_i - CEM_i$) at a given point in time i

When calculating the arithmetic mean of the difference of a flow monitor data set, be sure to correct the monitor measurements for moisture if applicable.

7.3.2 Standard Deviation. Calculate the standard deviation, S_d, of a data set as follows

$$S_d = \left[\frac{\sum_{i=1}^{n} d_i^2 - \left[\frac{\sum_{i=1}^{n} d_i}{n} \right]^2}{n-1} \right]^{1/2} \qquad \text{(Eq. 7-3)}$$

7.3.3 Confidence Coefficient. Calculate the confidence coefficient (one-tailed), cc, of a data set as follows.

$$CC = t_{0.025} \frac{S_d}{\sqrt{n}} \qquad \text{(Eq. 7-4)}$$

where:

$t_{0.025}$ = t value (see Table 7-1).

TABLE 7-1 T-VALUES

n-1	$t_{0.025}$	n-1	$t_{0.025}$	n-1	$t_{0.025}$
1	12.706	12	2.179	23	2.069
2	4.303	13	2.160	24	2.064
3	3.182	14	2.145	25	2.060
4	2.776	15	2.131	26	2.056
5	2.571	16	2.120	27	2.052
6	2.447	17	2.110	28	2.048
7	2.365	18	2.101	29	2.045
8	2.306	19	2.093	30	2.042
9	2.262	20	2.086	40	2.021
10	2.228	21	2.080	60	2.000
11	2.201	22	2.074	>60	1.960

7.3.4 *Relative Accuracy.* Calculate the relative accuracy of a data set using the following equation.

$$RA = \frac{|d| + |cc|}{RM} \times 100 \qquad \text{(Eq. 7-5)}$$

where

RM = Arithmetic mean of the reference method values.

Units where the average of the monitor measurements of SO_2 concentration during the relative accuracy test audit is less than or equal to 250.0 ppm may use an alternative standard for SO_2 pollutant concentration monitor relative accuracy defined in terms of |d|. For these units, |d| shall not exceed 15.0 ppm.

Units where the average of the flow monitor measurements of stack gas velocity during the relative accuracy test audit is less than or equal to 10.0 fps may use an alternative standard for flow monitor relative accuracy, defined in terms of |d|. For these units, |d| shall not exceed 1.0 fps.

7.4 Relative Accuracy for NO_x Continuous Emission Monitoring Systems. Analyze the relative accuracy test audit data from the reference method tests for NO_x continuous emissions monitoring system as follows.

7.4.1 *NO_x* Emission Rate (Instrumental Method). For each Method 7E sample run, multiply C_{NO_x}, the NO_x concentration in ppm, by 1.194×10^{-7} (lb/dscf)/ppm, to convert it to units of lb/dscf. Then, use the diluent (O_2 or CO_2) reference method results for the run to convert C_{NO_x} from lb/dscf to lb/mmBtu units. Use Equation 2-3 or 2-4 in appendix E of this part, as appropriate.

7.4.2 *NO_x Emission Rate (Wet Chemistry).* For each Method 7, 7A, 7B, 7C, or 7D sample run, calculate C_{NO_x}, the NO_x concentration expressed as NO_2, using the data reduction procedures in the applicable method. For grab samples, C_{NO_x} is the average of all samples taken during the run. If C_{NO_x} is in mg/dscm, multiply by 6.24×10^{-8} to convert it to lb/dscf. Then, use the diluent (O_2 or CO_2) reference method results for the run to convert from lb/dscf to lb/mmBtu. Use Equation 2-3 or 2-4 in appendix E of this part, as applicable.

7.4.3 *NO_x Emission Rate (Monitoring System).* For each test run in a data set, calculate the average NO_x emission rate (in lb/mmBtu), by means of the data acquisition and handling system, during the time period of the test run. Tabulate the results as shown in example Figure 2.

7.4.4 *Relative Accuracy.* Use the equations and procedures in Section 7.3 above to calculate the relative accuracy for the NO_x continuous emission monitoring system. In using Equation 7-2, "d" shall, for each run, be the difference between the NO_x emission rate values (in lb/mmBtu) obtained from the reference method data and the NO_x continuous emission monitoring system.

Units where the average of the monitoring system measurements during the relative accuracy test audit is less

than or equal to 0.50 lb/mmBtu may use an alternative standard for NO_x continuous emission monitoring system relative accuracy defined in terms of $|d|$. For these units, $|d|$ shall not exceed 0.05 lb/mmBtu.

7.5 *Relative Accuracy for Combined SO_2-Flow Monitoring Systems.* Beginning on January 1, 2000, use the equations and procedures in Section 7.3 above to calculate the relative accuracy for the combined SO_2-flow monitoring system. In using Equation 7-2, "d" shall, for each run, be the difference between the SO_2 emission rate values (in lb/hr) obtained from the reference method data for SO_2 concentration and flow rate and the combined SO_2–flow monitoring system.

7.6 Bias Test and Adjustment Factor. Test the relative accuracy test audit data sets for SO_2 pollutant concentration monitors, flow monitors, NO_x continuous emission monitoring systems and, beginning January 1, 2000, for combined SO_2-flow monitoring systems for bias using the procedures outlined below.

7.6.1 *Arithmetic Mean.* Calculate the arithmetic mean of the difference, d, of the data set using Equation 7-2. To calculate bias for an SO_2 pollutant concentration monitor, "d" shall, for each paired data point, be the difference between the SO_2 concentration values (in ppm) obtained from the reference method and the monitor. To calculate bias for a flow monitor, "d" shall, for each paired data point be the difference between the flow rate values (in scfh) obtained from the reference method and the monitor. To calculate bias for a NO_x continuous emission monitoring system, "d" shall, for each paired data point, be the difference between the NO_x emission rate values (in lb/mmBtu) obtained from the reference method and the monitoring system. To calculate bias for a combined SO_2- flow monitoring system, "d" shall, for each paired data point, be the difference between the SO_2 mass emissions per unit time (in lb/hr) obtained from the reference methods and the monitoring system.

Bias tests for flow monitors and, beginning on January 1, 2000, for combined SO_2-flow monitoring systems shall be performed at the normal operating level only.

7.6.2 *Standard Deviation.* Calculate the standard deviation, S_d, of the data set using Equation 7-3.

7.6.3 *Confidence Coefficient.* Calculate the confidence coefficient, cc, of the data set using Equation 7-4.

7.6.4 *Bias Test.* If the mean difference, d, is greater than $|cc|$, the monitor or monitoring system has failed to meet the bias test requirement. For flow monitor bias tests and, beginning on January 1, 2000, for combined SO_2-flow monitoring system bias tests, if the mean difference, d is greater than $|cc|$ at the normal operating level, the monitor has failed to meet the bias test requirement.

7.6.5 *Bias Adjustment.* If the monitor or monitoring system fails to meet the bias test requirement, the owner or operator shall adjust the values obtained from the monitor using the following equation.

$$CEM_i^{Adjusted} = CEM_i^{Monitor}\left(1 + \frac{|\bar{d}|}{\overline{CEM}}\right) \quad \text{(Eq. 7-6)}$$

where:

$CEM_i^{Monitor}$ = Data (measurements) provided by the monitor at time i.

$CEM_i^{Adjusted}$ = Data value, adjusted for bias, at time i.

$\bar{d}$ = Arithmetic mean of the difference obtained during the failed bias test using Equation 7-2.

$\overline{CEM}$ = Mean of the data values provided by the monitor during the failed bias test.

This adjustment shall be applied prospectively to all monitor or monitoring system data from the date and time of the failed bias test until the date and time of a relative accuracy test audit that does not show bias.

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	Day	Date and time	Reference value	Monitor value	Difference	Percent of reference value
Low-level						
Mid-level						
High-level						

Figure 1. Calibration error determination.

Run No.	Date and time	SO_2			Date and time	NO_x [b]			Date and time	CO_2 or O_2 [a] (Diluent)			Date and time	CO_2 (Pollutant)		
		RM	M	Diff		RM	M	Diff		RM	M	Diff		RM	M	Diff
		ppm [c]				ppm [c]				% [c]	% [c]			ppm [c]		
1																
2																
3																
4																
5																
6																
7																
8																
9																
10																
11																
12																
Average																
Confidence Interval																
Accuracy																

[a] For steam generators

[b] Average of three samples, if grab-sampling is used.

[c] Make sure that RM and M data are on a consistent basis, either wet or dry.

Figure 2: Relative accuracy determination (pollutant and diluent monitors).

Run No.	Date and time	Stack moisture RM	Stack moisture M	Stack moisture Diff	Date and time	Flow rate (40%) RM	Flow rate (40%) M	Flow rate (40%) Diff	Date and time	Flow rate (60%) RM	Flow rate (60%) M	Flow rate (60%) Diff	Date and time	Flow rate (90%) RM	Flow rate (90%) M	Flow rate (90%) Diff
		% H_2O				(scf/hr) *				(scf/hr) *				(scf/hr) *		
1																
2																
3																
4																
5																
6																
7																
8																
9																
10																
11																
12																
Average																
Confidence Interval																
Accuracy																

* Make sure that RM and M data are on a wet basis.

Figure 2 (cont'd): Relative accuracy determination (moisture and flow monitors).

Run No.	Date and time	NO_x RM data		NO_x system		
		NO_x	O_2/CO_2	RM	M	Diff
		( ) [a]	%	lb/mmBtu		
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
Average						
Confidence Interval						
Accuracy						

[a] Specify units; ppm, lb/dscf, mg/dscm

Figure 2 (cont'd): Relative accuracy determination (NO_x/diluent combined system).

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Appendix B to Part 75—Quality Assurance and Quality Control Procedures

1. Quality Control Program.

Each owner or operator of an affected unit shall develop and implement a quality control program for the overall continuous emission monitoring system and its components. As a minimum, each quality control program must include a written plan that describes in detail complete, step-by-step procedures and operations for each of the following activities.

1.1 Calibration Error Test Procedures. Identify calibration error test procedures peculiar to the continuous emission monitoring system that may require variance from the procedures in appendix A of this part (e.g., how gases shall be injected, adjustments of flow rates and pressures, length of time for injection of calibration gases, steps for obtaining calibration error, and when calibration adjustments should be made).

1.2 Calibration Adjustments. Explain how each component of the continuous emission monitoring system will be adjusted to provide correct responses to calibration gases and reference signals both initially and after repairs or corrective action. Identify equations, conversion factors, assumed moisture content, and other factors affecting calibration of the continuous emission monitoring system.

1.3 Preventive Maintenance. Identify procedures, including those specified by the manufacturers, needed to maintain the continuous emission monitoring system in proper operating condition. Include provisions for maintaining an inventory of spare parts.

1.4 Audit Procedures. Identify procedures and details peculiar to the installed continuous emission monitoring system that are to be used for relative accuracy test audits, such as sampling and analysis methods.

1.5 Recordkeeping and Reporting. Describe procedures that will be used to implement the recordkeeping and reporting requirements in § 75.22 and § 75.23 of the regulation.

2. Quality Assurance Procedures.

2.1 Daily Assessments.

2.1.1 *Calibration Error Tests for Pollutant Concentration and Diluent Gas Monitors.* Test, record, and compute the calibration error of each pollutant concentration and diluent gas monitor at least once daily (approximately every 24 hr) at two concentrations: (1) Low-level—zero to 20 percent of span, and (2) high-level—80 to 100 percent of span. Perform daily calibration error tests in accordance with the procedures and equations in sections 6 and 7 of appendix A of this part and use only Protocol 1, NIST/EPA-approved certified reference material, or standard reference material gases. Do not make calibration adjustments for low-level concentration measurements before completion of the high-level concentration calibration error checks. Perform daily calibration error tests for both ranges of a dual-range monitor.

2.1.2 *Calibration Error or Electronic Drift Test for Flow Monitors.* Perform manufacturer-recommended zero and calibration procedures on each flow monitor daily, or more frequently if recommended by the manufacturer. Record flow monitor output before and after any adjustments. Set instrument span so that the average volumetric flow lies between 40.0 and 75.0 percent of span. Whenever the monthly average volumetric flow falls below 40.0 percent or rises above 75.0 percent of span, adjust the span so that the average volumetric flow is within the cited ranges.

Test, record, and quantify the calibration error of each flow monitor that performs daily calibration error tests (approximately every 24 hours) at two gas flow rates: (1) low-level—the minimum safe and stable operating level, and (2) high-level—the maximum normal operating level. Daily calibration error tests for flow monitors must provide a check of the entire measurement system from the probe tip through the data acquisition and handling system.

Test, record, and quantify the electronic drift of each flow monitor that does not perform daily calibration error tests at two electronic signal levels: (1) 45 to 75 percent of span, and (2) 80 to 100 percent of span. Daily electronic drift tests for flow monitors must provide a check of all electronic components of the flow monitor.

2.1.3 *Recalibration.* The calibration must, at a minimum, be adjusted whenever the daily calibration error exceeds the limits of the applicable performance specification for the pollutant concentration monitor, diluent gas monitor, or flow monitor in appendix A of this part.

2.1.4 *Out-of-Control Period.* An out-of-control period occurs when the calibration error or electronic drift exceeds twice the applicable specification (i.e., when the calibration error of a pollutant concentration monitor exceeds 5.0 percent, the calibration error of a diluent gas monitor exceeds 1.0 percent, or the calibration error or electronic drift of a flow monitor exceeds 6.0 percent). The out-of-control period begins with the hour of the failed calibration error or electronic drift test and ends with the hour of the satisfactory calibration error or electronic drift test following recalibration or corrective action.

2.1.5 *Data Recording.* Record and tabulate all calibration error and electronic drift test data according to month, day, and magnitude in either ppm, percent volume, or scfh. Program monitors that automatically adjust data to the corrected calibration values (e.g., microprocessor control) to record either: (1) The unadjusted concentration or flow rate measured in the calibration error test prior to resetting the calibration, or (2) the magnitude of any adjustment.

2.1.6 *Interference Check.* For ultrasonic and differential pressure flow monitors, perform automatic timed periodic back purging (simultaneously on both sides of the probe), or equivalent method of sufficient force and frequency to keep the transceiver surface/sample port, and the probe and lines, respectively, free of obstructions. Inspect and clean the probe of thermal flow monitors at a frequency (daily if necessary) that ensures that the probe remains clean at all times.

An out-of-control period occurs whenever an interference is identified. The out-of-control period begins with the hour of the failed interference check and ends with the hour following removal of the interference.

2.2 Quarterly Assessments.

2.2.1 *Three-Point Calibration Error Test.* Perform a three-point calibration error test for each pollutant concentration and diluent gas monitor at least once during each calendar quarter (approximately every 3 months) in accordance with the following procedures.

Challenge each pollutant concentration or diluent gas monitor with Protocol 1, NIST/EPA-approved certified reference material, or standard reference material calibration gases at the three concentrations specified in section 5.2 in appendix A of this part. Perform separate calibration error tests for each range of a dual-range monitor.

Introduce the calibration gas at the probe. Operate each monitor in its normal sampling mode, i.e., pass the audit gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as is practical. Challenge the monitor three times, but not in succession, at each concentration. For each concentration, use the average of the three responses to determine the calibration error. Use separate audit gas cylinders for each concentration.

2.2.2 *Interference Checks.* Perform a leak check and pressure transducer check on each differential pressure flow monitor at least once during each calendar quarter.

2.2.3 *Relative Accuracy Test Audits for Flow Monitors.* Perform a relative accuracy test audit for each flow monitor that does not perform daily calibration error tests at least once during each calendar quarter in accordance with the procedures specified in section 6.6 of appendix A of this part. (Quarterly test audits shall be performed at normal operating load and shall be no less than two months apart). However, a relative accuracy test audit may be performed during the second quarter following a relative accuracy test audit instead of the next consecutive quarter under the following conditions: (1) Prior to January 1, 2000, when the relative accuracy is 10.0 percent or less during the previous audit; and (2) on and after January 1, 2000, when the relative accuracy is 7.5 percent or less during the previous audit. Using the data from the relative accuracy test audit, calculate relative accuracy and bias for each flow monitor in accordance with the procedures and equations specified in section 7 of appendix A of this part.

A maximum of two relative accuracy test audit trials may be performed for the purpose of achieving the results required for less frequent relative accuracy test audits. Whenever two trials are performed, however, the results of the second (later) trial must be used in calculating relative accuracy and bias.

2.2.4 *Out-of-Control Period.* An out-of-control period occurs under any of the following conditions: (1) The calibration error at any of the three concentrations or flow rates in the quarterly three-point calibration error test exceeds twice the applicable specification in section 2.3 of appendix A of

this part, or (2) prior to January 1, 2000, the relative accuracy of the flow monitor exceeds 15.0 percent, or (3) on and after January 1, 2000, the relative accuracy of the flow monitor exceeds 10.0 percent. The out-of-control period begins with the hour of the failed three-point calibration error test or relative accuracy test audit and ends with the hour of a satisfactory three-point calibration error test or relative accuracy test audit following corrective action and/or monitor repair.

2.2.5 *Bias Adjustment Factor.* If a flow monitor fails the bias test specified in section 7.6 of appendix A of this part, the owner or operator shall use the bias adjustment factor given by Equation 7–6 to adjust the monitored data. This adjustment factor shall be applied prospectively to the flow monitor data from the date and time of the failed bias test until the date and time of a relative accuracy test audit that does not show bias.

2.3 Semiannual Assessments.

2.3.1 *Relative Accuracy Test Audit.* Perform a component and system relative accuracy test audit semiannually and no less than 4 months apart for each SO_2 pollutant concentration monitor, flow monitor that performs daily calibration error tests, and NO_x continuous emission monitoring system, and, beginning January 1, 2000, combined SO_2-flow monitoring system.

Relative accuracy test audits may be performed on an annual basis in the fourth quarter following a relative accuracy test audit rather than on a semiannual basis in the second quarter under any of the following conditions: (1) The relative accuracy during the previous audit for an SO_2 pollutant concentration monitor or NO_x continuous emissions monitoring system is 7.5 percent or less; (2) prior to January 1, 2000, the relative accuracy during the previous audit for a flow monitor is 10.0 percent or less; (3) on and after January 1, 2000, the relative accuracy during the previous audit for a flow monitor is 7.5 percent or less. A maximum of two relative accuracy test audit trials may be performed for the purpose of achieving the results required to qualify for less frequent relative accuracy test audits. Whenever two trials are performed, however, the results of the second (later) trial must be used in calculating relative accuracy and bias.

2.3.2 *Out-of-Control Period.* An out-of-control period occurs under any of the following conditions: (1) The relative accuracy of an SO_2 pollutant concentration monitor or a NO_x continuous emission monitoring system exceeds 10.0 percent; (2) prior to January 1, 2000, the relative accuracy of a flow monitor exceeds 15.0 percent; or (3) on and after January 1, 2000, the relative accuracy of a flow monitor exceeds 10.0 percent. The out-of-control period begins with the hour of the failed relative accuracy test audit and ends with the hour of a satisfactory relative accuracy test audit following corrective action and/or repair of the monitor or monitoring system.

2.3.3 *Bias Adjustment Factor.* If an SO_2 pollutant concentration monitor, flow monitor, or NO_x continuous emission monitoring system fails the bias test specified in section 7.6 of appendix A of this part, the owner or operator shall use the bias adjustment factor given by Equation 7–6 to adjust the monitored data. This adjustment factor shall be applied prospectively to the monitor or monitoring system data from the date and time of the failed bias test until the date and time of a relative accuracy test audit that does not show bias.

2.4 Annual Assessments.

2.4.1 *Three-Level Relative Accuracy Test Audit for Flow Monitors.* Perform relative accuracy test audits for each flow monitor at each of three gas flow rates (or unit operating levels): (1) The minimum safe and stable operating level, (2) 90.0 percent or greater of the maximum operating level, and (3) at the normal operating level or an evenly spaced intermediary flow velocity if the normal operating level is within 10.0 percent of (1) or (2) above. These test audits shall be performed while the unit (or units, if more than one unit exhausts into the stack or duct) is combusting primary fuel and must be completed within a 7-day period.

Using the data from the relative accuracy test audits, calculate monitor relative accuracy at each of the three flow rates (operating levels) and bias at the normal operating level in accordance with the procedures and equations specified in section 7 of appendix A of this part.

2.4.2 *Relative Accuracy Test Audit for Combined SO_2-Flow Monitoring System.* Beginning January 1, 2000, at least once every four calendar quarters, perform relative accuracy test audits for each combined SO_2-flow monitoring system at each of three gas flow rates (or unit operating levels): (1) The minimum safe and stable operating level, (2) 90.0 percent or greater of the maximum operating level, and (3) at the normal operating level or an evenly spaced intermediary flow velocity if the normal operating level is within 10.0 percent of (1) or (2) above. These combined system test audits shall be performed concurrently with the test audits for the SO_2 pollutant concentration monitor and the flow monitor while the unit (or units, if more than one unit exhausts into the stack or duct) is burning primary fuel. The test audits must be completed within a 7-day period.

Using the data from the relative accuracy test audits, calculate the relative accuracy of the combined SO_2-flow monitoring system at each of the three flow rate (operating levels) and bias at the normal operating level in accordance with the procedures and equations specified in Section 7 of appendix A of this part.

2.4.3 *Out-of-Control Period.* An out-of-control period occurs under any of the following conditions: (1) Prior to January 1, 2000, the relative accuracy of a flow monitor at any of the three operating levels exceeds 15.0 percent; (2) on or after January 1, 2000, the relative accuracy of a flow monitor at any of the three operating levels exceeds 10.0 percent; or (3) on and after January 1, 2000, the relative accuracy of a combined SO_2-flow monitoring system exceeds 10.0 percent at any of the three operating levels. The out-of-control period begins with the hour of the failed three-level relative accuracy test audit and ends with the hour of a satisfactory three-level relative accuracy test audit following corrective action and/or repair of the monitor or monitoring system.

2.4.4 *Bias Adjustment Factor.* If a flow monitor fails the bias test specified in section 7.6 of appendix A of this part, the owner or operator shall use the bias adjustment factor give by Equation 7–6 of appendix A to adjust the monitored data. This adjustment factor shall be applied prospectively to the monitor data from the date and time of the failed bias test until the date and time of a relative accuracy test audit that does not show bias.

2.4.5 *Other Audits.* Affected units may be subject to unannounced relative accuracy test audits at any time. If a monitor or monitoring system fails the relative accuracy test during the unannounced audit, the monitor or monitoring system shall be considered to be out of control beginning with the date and time of the unannounced audit and continuing until a successful audit test is completed following corrective action. If a monitor or monitoring system fails the bias test during an unannounced audit, the owner or operator shall use the bias adjustment factor given by Equation 7–6 in appendix A of this part to adjust the monitored data. This adjustment factor shall be applied from the date and time of the unannounced audit until the date and time of a relative accuracy test audit that does not show bias.

Appendix C to Part 75—Missing Data Statistical Estimation Procedures

1. Parametric Monitoring Procedure for Missing SO_2 Concentration Data.

1.1 Applicability. The owner or operator of any affected unit equipped with flue gas SO_2 emission controls and inlet and outlet SO_2 pollutant concentration monitors may apply to the Administrator for approval and certification of a parametric method for calculating substitute data for missing data periods. Such method may be used to parametrically estimate the removal efficiency of the SO_2 emission controls which, with the monitored SO_2 inlet concentration data, may be used to estimate the average concentration of SO_2 emissions discharged to the atmosphere. Such method may be used subsequent to approval by the Administrator for filling in missing SO_2 concentration data when data from the outlet SO_2 pollutant concentration monitor have been available and recorded for 90.0 percent or more of the total unit operating hours during the previous 365 days.

1.2 Demonstration Requirements. Continuously monitor, determine, and record hourly averages for the parameters specified below. At least four evenly spaced data points are required for a valid hourly average, except during periods of calibration, quality assurance, maintenance or repair activities, during which two data points per hour are sufficient.

1.2.1 Wet Flue Gas Desulfurization System (Wet Scrubber).

1.2.1.1 Number of scrubber modules in operation.

1.2.1.2 Feed rate of makeup slurry to each scrubber module (gal per min).

1.2.1.3 Percent solids in slurry.

1.2.1.4 pH of the solids slurry in each scrubber module.

1.2.1.5 Pressure differential across each scrubber module (inches of water column).

1.2.1.6 Power load of unit (MWe).

1.2.1.7 Average sulfur content of fuel combusted each day (lb/mmBtu).

1.2.2 Dry Flue Gas Desulfurization System (Dry Scrubber).

1.2.2.1 Number of scrubber modules in operation.

1.2.2.2 Feed rate of makeup slurry to each scrubber module (gal per min).

1.2.2.3 Percent solids in slurry.

1.2.2.4 Dew point approach temperature for each scrubber module (degrees Fahrenheit).

1.2.2.5 Pressure differential across each scrubber module (inches of water column).

1.2.2.6 Power load of unit (MWe).

1.2.2.7 Average sulfur content of fuel combusted each day (lb/mmBtu).

1.2.3 If a technology other than conventional wet or dry scrubbing is selected for flue gas desulfurization, then appropriate parameters will be determined at the discretion of the Administrator on a case-by-case basis.

1.2.4 Establish a method for correlating hourly averages of the parameters identified above with the percent removal efficiency of the SO_2 emission controls under varying unit operating loads. Equation 2 in § 75.12(d) of this part may be used to estimate the percent removal efficiency of the SO_2 emission controls.

1.2.5 Use the following equation to calculate substitute data for filling in missing (outlet) SO_2 pollutant concentration monitor data.

$$M_o = I_c \quad (1-E) \qquad \text{(Eq. 1-1)}$$

where:

M_o = Substitute data for outlet SO_2 concentration, ppm.

I_c = Recorded inlet SO_2 concentration, ppm.

E = Removal efficiency of SO_2 emission controls as determined by the correlation procedure described in Section 1.2.4.

1.2.6 If both the inlet and the outlet SO_2 pollutant concentration monitors are unavailable simultaneously, the maximum inlet SO_2 concentration for the corresponding unit load recorded during the previous 30 days shall be used to substitute for the inlet SO_2 concentration in Equation 1-1.

1.2.7 The owner or operator shall apply to the Administrator for approval and certification of the parametric substitution procedure for filling in missing SO_2 concentration data using the established criteria and information identified above. Such procedure shall not be used until approved by the Administrator.

2. Parametric Monitoring Procedure For Missing NO_x Emission Rate Data.

2.1 Applicability. The owner or operator of an affected unit equipped with post-combustion NO_x emission controls and inlet and outlet NO_x continuous emission monitoring systems (NO_x pollutant concentration monitor and diluent gas monitor) may apply to the Administrator for approval and certification of a parametric method for calculating substitute data for missing data periods. Such method may be used to parametrically estimate the removal efficiency of the post-combustion NO_x emission controls which, with monitored NO_x inlet emission rate data, may be used to estimate the average emission rate of NO_x discharged to the atmosphere. Such method may be used subsequent to approval by the Administrator for filling in missing NO_x emission rate data when data from the outlet NO_x continuous emission monitoring system have been available and recorded for 90.0 percent or more of the total unit operating hours during the previous 365 days.

2.2 Demonstration Requirements.

2.2.1 Continuously monitor, determine, and record hourly averages for the parameters specified below. At least four data points are required for a valid hourly average, except during periods of calibration, quality assurance, maintenance or repair activities, during which two data points per hour are sufficient.

2.2.1.1 Inlet air flow rate to the unit (scfh).

2.2.1.2 Excess oxygen concentration of flue gas at stack outlet (percent).

2.2.1.3 Carbon monoxide concentration of flue gas at stack outlet (ppm).

2.2.1.4 Temperature of flue gas at outlet of the unit (degrees Fahrenheit).

2.2.1.5 Other parameters of the post-combustion NO_x emission controls specific to the emission reduction process.

2.3 Establish a method for correlating hourly averages of the parameters identified above with the percent removal efficiency of the post-combustion NO_x emission controls under varying unit operating loads.

2.4 Use the following equation to calculate substitute data for filling in missing (outlet) NO_x emission rate data.

$$M_o = I_c \quad (1-E) \qquad \text{(Eq. 2-1)}$$

where:

M_o = Substitute data for outlet NO_x emission rate, lb/mmBtu.

I_c = Recorded inlet NO_x emission rate, lb/mmBtu.

E = Removal efficiency of post-combustion NO_x emission controls determined by the correlation procedure described in Section 2.3.

2.5 If both the inlet and outlet NO_x continuous emission monitoring systems are unavailable simultaneously, the maximum inlet NO_x emission rate for the corresponding unit load recorded during the previous 30 days shall be used to substitute for the inlet NO_x emission rate in Equation 2-1.

2.6 The owner or operator shall apply to the Administrator for approval and certification of the substitute procedure for filling in missing NO_x emission rate data using the established criteria and information identified above. Such procedure shall not be used until approved by the Administrator.

3. Load-Based Procedure for Missing Flow Rate and NO_x Emission Rate Data.

3.1 Applicability. This procedure may be used in accordance with the provisions of this part to provide substitute data for volumetric flow (scfh) and NO_x emission rate (lb/mmBtu).

3.2 Procedure.

3.2.1 Establish 13 operating load ranges defined in terms of percent of the maximum integrated hourly gross load of the unit, in gross megawatts (MWge) as shown in Table C-1.

TABLE C-1.—DEFINITION OF OPERATING LOAD RANGES FOR LOAD-BASED SUBSTITUTION DATA PROCEDURE

Operating load range	Percent of maximum integrated hourly gross load (%)
1	1-20
2	21-40
3	41-50
4	51-55
5	56-60
6	61-65
7	66-70
8	71-75
9	76-80
10	81-85
11	86-90
12	91-95
13	96-100

3.2.2 Beginning with the first hour of unit operation after installation and certification of the flow monitor and the NO_x continuous emission monitoring system and continuing during each consecutive 365 days of operation of the monitor and monitoring system thereafter, calculate and record the following information for each hour of unit operation.

3.2.2.1 A number, 1 through 13, that identifies the operating load range corresponding to the integrated hourly gross load of the unit recorded for that hour.

3.2.2.2 A running average of the hourly flow rates recorded by the flow monitor, in scfh, for all hours the unit operated within the identified load range during the previous 365 days of operation of the flow monitor.

3.2.2.3 The 90th percentile value of hourly flow rates, in scfh, within the identified operating load range during the previous 365 days of operation of the flow monitor.

3.2.2.4 The 90th percentile value of hourly flow rates, in scfh, within the identified operating load range during the previous 30 days of operation of the flow monitor.

3.2.2.5 A running average of the hourly NO_x emission rate, in lb/mmBtu, for all hours of operation within the identified operating load range during the previous 365 days of operation of the NO_x continuous emissions monitoring system.

3.2.2.6 The 90th percentile value of hourly NO_x emission rates, in lb/mmBtu, within the identified operating load range during the previous 365 days of operation of the NO_x continuous emissions monitoring system.

3.2.2.7 The 90th percentile value of hourly NO_x emission rates, in lb/mmBtu, within the identified operating load range during the previous 30 days of operation of the NO_x continuous emissions monitoring system.

3.2.3 When a bias adjustment is necessary for the flow monitor and/or the NO_x continuous emission monitoring system, use the adjusted monitor or monitoring system data in all determinations of averages

and 90th percentile values within a load range.

3.2.4 Use the calculated averages and 90th percentile values to substitute for missing flow rate and NO_x emission rate data according to the procedures in § 75.12 and § 75.13 of this part.

4. Sulfur Content-Based Procedure for Missing SO_2 Concentration Data.

4.1 Applicability. This procedure may be used in accordance with the provisions of this part to provide substitute data for SO_2 concentration (ppm).

4.2 Procedure.

4.2.1 Sample (as-fired after the bunker), analyze, and record the percent of sulfur by weight in the fuel combusted once each 6 hours. For coal, collect a sample in accordance with ASTM D2234–89, "Standard Test Methods for Collection of a Gross Sample of Coal" using Type I, Condition B or C sampling, and perform the analysis in accordance with ASTM D3176–89, "Standard Method for Ultimate Analysis of Coal and Coke" or ASTM D3177–89, "Standard Test Methods for Total Sulfur in the Analysis Sample of Coal and Coke" (incorporated by reference in § 75.9). For oil, perform the analysis in accordance with ASTM D129, ASTM D1552, ASTM D2622, or ASTM D4294 (incorporated by reference in § 75.9).

4.2.2 Establish 25 sulfur content ranges to include values from zero to greater than 6 percent sulfur content in the fuel combusted by the unit, where sulfur content is defined in terms of the percent sulfur by weight measured in the fuel. Define each sulfur content range to span 0.25 percent sulfur as shown in Table C–2.

TABLE C–2.—DEFINITION OF SULFUR CONTENT RANGES FOR SULFUR CONTENT-BASED SUBSTITUTION DATA PROCEDURE

Sulfur content range	Percent of sulfur measured in fuel (%)
1	0.00–0.25
2	0.26–0.50
3	0.51–0.75
4	0.76–1.00
5	1.01–1.25
6	1.26–1.50
7	1.51–1.75
8	1.76–2.00
—	—
24	5.76–6.00
25	>6.00

4.2.3 Beginning with the first hour of unit operation after installation and certification of the SO_2 pollutant concentration monitor and continuing during each consecutive 365 days thereafter, calculate and record the following information for each 6-hr period of unit operation.

4.2.3.1 A number, 1 through 25, that identifies the sulfur content range corresponding to the percent sulfur measured in the fuel for the 6-hr period. Include each of the hourly SO_2 concentrations recorded by the SO_2 pollutant concentration monitor during the 6-hr period in the identified sulfur content range for the purpose of calculating 90th percentile values.

4.2.3.2 The 90th percentile value of the hourly SO_2 concentrations, in ppm, within the identified sulfur content range during the previous 365 days of operation.

4.2.3.3 The 90th percentile value of the hourly SO_2 pollutant concentrations, in ppm, within the identified sulfur content range during the previous 30 days of operation.

4.2.4 When a bias adjustment is necessary for the SO_2 pollutant concentration monitor, use the adjusted monitor data in all determinations of 90th percentile values within a sulfur content range.

4.2.5 Use the calculated 90th percentile values to substitute for missing SO_2 concentration data according to the procedures in § 75.11 of this part. Whenever a sulfur content range has fewer than 20 hourly values of SO_2 concentration recorded by the SO_2 pollutant concentration monitor, use the next higher sulfur content range that has at least 20 values for each substitution involving 90th percentile calculations (unless there is no higher range that has at least 20 values).

4.2.6 To identify the appropriate sulfur content range for each hour of missing data, use the measured percent sulfur by weight in the fuel taken for that hour or, if no sample was taken during the missing hour, use the average of the measured percent sulfur by weight in the fuel for the 6-hr sample immediately before and the 6-hr sample immediately following the missing hour.

Appendix D to Part 75—Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units

1. Applicability.

This procedure may be used in lieu of continuous SO_2 pollutant concentration and flow monitors for the purpose of determining hourly SO_2 emissions from: (1) Gas-fired units that use fuel oil (including diesel fuel) as the only backup fuel where oil firing provides less than 10.0 percent of the annual heat input to the unit; or (2) oil-fired units that use natural gas as the only other fuel where oil firing provides 10.0 percent or more of the annual heat input to the unit.

2. Procedure.

2.1 When the unit is combusting oil, measure and record the flow of oil consumed on an hourly basis. The flow of oil must be measured with an in-line fuel flowmeter and the data automatically recorded. Measure the flow of all oil entering the unit. Any pipe returning fuel to a pipe that provides oil to the unit requires an in-line fuel flowmeter.

2.1.1 Each fuel flowmeter used to meet the requirements of this protocol shall meet a relative accuracy specification of 2.0 percent as measured under laboratory conditions by the manufacturer or by the owner or operator.

2.1.2 Recalibrate each fuel flowmeter at least annually or more frequently if required by manufacturer specifications to meet the requirements of this protocol.

2.2 Perform sampling and analysis of as-fired oil to determine the percentage of sulfur by weight in the oil.

2.2.1 Perform oil sampling every day the unit is combusting oil. Use the standard method described in Section 2.2.1.1 below for oil-fired units and either the standard method or the exception method described in section 2.2.1.2 below for gas-fired units.

2.2.1.1 *Standard Method for Oil Sampling.* Conduct flow proportional oil sampling or continuous drip oil sampling in accordance with ASTM 4177, "Standard Method for Automatic Sampling of Petroleum and Petroleum Products" (incorporated by reference under § 75.9), every day the unit is combusting oil. Extract oil at least once every hour and blend into a daily composite sample. The sample compositing period may not exceed 24 hr.

2.2.1.2 *Exception.* For a gas-fired unit, representative, as-fired oil samples may be taken manually every 24 hr according to ASTM D4057, "Standard Method for Manual Sampling of Petroleum and Petroleum Products" (incorporated by reference under § 75.9), provided that the highest fuel sulfur content recorded at that unit from the most recent 30 daily samples is used for the purposes of calculating SO_2 emissions under section 2.9.

2.2.2 Split and label each daily oil sample. Maintain a portion of each daily sample throughout the calendar year (at least 200 cc) for not less than 6 months after December 31 of that year

2.2.3 Analyze oil samples for percent sulfur content by weight in accordance with ASTM D129, ASTM D1552, ASTM D2622, or ASTM D4294 (incorporated by reference under § 75.9).

2.3 Where the flowmeter records volumetric flow rather than mass flow, analyze daily oil samples to determine the density or specific gravity of the oil.

2.3.1 Determine the density or specific gravity of the oil sample in accordance with ASTM D941–88, ASTM D1217–86, ASTM D1481–86, ASTM D1480–86, ASTM D1298–85, or ASTM D4052–86 (incorporated by reference under § 75.9).

2.3.2 Convert oil volume to oil mass using ASTM D1250–80 (Reapproved 1984), "Standard Petroleum Measurement Tables" (incorporated by reference under § 75.9).

2.3.3 Calculate hourly oil mass using hourly oil flow measurements and the density or specific gravity of the daily oil sample.

2.4 Analyze daily oil samples to determine the heat content of the fuel.

2.4.1 Determine oil heat content in accordance with ASTM D240–87 or D2382–88 (incorporated by reference under § 75.9).

2.4.2 Calculate the hourly heat input to the unit from oil by multiplying the heat content of the daily oil sample by the hourly oil mass.

2.5 Results from the daily oil sample analysis must be available the day after the sample is composited or taken.

2.6 When data from a daily oil sample analysis are missing or invalid, substitute the highest measured sulfur content or oil density recorded during the previous 365 days.

2.7 When data from the fuel flowmeter are missing or invalid for less than 24 hr, substitute for each hour in the missing data period the average hourly oil flow rate recorded by the fuel flowmeter during the previous 365 days at the same unit load (in

MWe) recorded for the missing hour. If no data are available at the same unit load, use the average hourly oil flow rate recorded at the closest, higher unit load.

2.8 When data from the fuel flowmeter are missing or invalid for more than 24 hr, substitute for each hour in the missing data period the second highest hourly oil flow rate measured by the fuel flowmeter during the previous 365 days.

2.9 Calculate total SO_2 mass emissions for each hour by multiplying the mass of oil consumed in lb/hr times the percentage of sulfur in oil by weight times 2.0.

2.9.1 Use the following equation to calculate SO_2 mass emissions per hour (in lb/hr).

$M_{SO2}=2.0\times M_{oil}\times \%S_{oil}/100.0$ (Eq. 2–1)

where:

M_{SO2} = Hourly mass of SO_2 emitted, lb/hr.
M_{oil} = Mass of oil consumed per hr, lb/hr.
$\%S_{oil}$ = Percentage of sulfur by weight measured in the sample.
2.0 = Ratio of g-mol SO_2/g-mol S.

2.9.2 Where the flowmeter records volumetric flow rather than mass flow, use the following equation to calculate the mass of oil consumed (in lb/hr).

$M_{oil}=V_{oil}\times D_{oil}$ (Eq. 2–2)

where:

M_{oil} = Mass of oil consumed per hr, lb/hr.
V_{oil} = Volume of oil consumed per hr, measured in scf, gal, or m^3.
D_{oil} = Density of oil, measured in lb/gal, lb/scf, or lb/m^3.

2.9.3 Calculate and record total daily SO_2 mass emissions by summing the hourly SO_2 mass emissions for each hour during that day when the unit combusted any oil.

2.9.4 Calculate and record total quarterly SO_2 mass emissions by summing hourly SO_2 mass emissions for each hour during that quarter when the unit combusted any oil.

2.9.5 For purposes of determining compliance with allowances held, calculate and record the total SO_2 mass emissions by summing hourly SO_2 mass emissions for each hour during that year when the unit combusted any oil.

Appendix E to Part 75—Conversion Procedures

1. Applicability.

Each owner or operator of an affected unit shall use the procedures in this appendix to convert measured data from the monitor or continuous emission monitoring system into the appropriate units required by the regulation in this part.

2. Procedures.

2.1 SO_2. Use the following procedures to compute the hourly emission rates of SO_2 in lb/hr.

2.1.1 When measurements of both SO_2 pollutant concentration and flow rate are on the same moisture basis, use the following equation to compute SO_2 hourly emission rates (in lb/hr).

$E_h=K\ C_h\ Q_h$ (Eq. 2–1)

where:

E_h = Hourly emission rate of SO_2, lb/hr.
$K=1.660\times10^{-7}$ for SO_2 (lb/scf)/ppm.
C_h = Hourly average pollutant concentration of SO_2, stack moisture basis, ppm.
Q_h = Hourly average volumetric flow rate, stack moisture basis, scfh.

2.1.2 When measurements by the SO_2 pollutant concentration monitor are on a dry basis and the flow rate monitor measurements are on a wet basis, use the following equation to compute SO_2 hourly emission rates (in lb/hr).

$E_h=K\ C_{hp}\ Q_{hs}\ (1-B_{we})$ (Eq. 2–2)

where:

E_h = Hourly emission rate of SO_2, lb/hr.
$K=1.660\times10^{-7}$ for SO_2 (lb/scf)/ppm.
C_{hp} = Hourly average pollutant concentration, ppm (dry).
Q_{hs} = Hourly average volumetric flow rate, scfh as measured (wet).
B_{we} = Hourly average stack moisture content, volume fraction.

2.1.3 Round all SO_2 emission rates to the same number of significant digits that are identified by the regulation (in lb/hr), but in no case less than the nearest 10 lb/hr. When hourly SO_2 emission rates are less than 1,000 lb/hr, round the emission rates to the nearest 1 lb/hr.

2.2 NO_x. Use the following procedures to convert continuous emission monitoring system measurements of NO_x concentration (ppm) and diluent concentration (percentage) into NO_x emission rates (in lb/mmBtu). Measurements of NO_x and diluent (O_2 or CO_2) concentrations must be performed on the same moisture (wet or dry) basis.

2.2.1 When the NO_x continuous emission monitoring system uses O_2 as the diluent, and measurements are performed on a dry basis, use the following conversion procedure:

$E=CF[20.9/(20.9\text{-percent } O_2)]$ (Eq. 2–3)

where E, C, F, and percent O_2 are defined in Section 2.2.3.

When measurements are performed on a wet basis, use the equations in 40 CFR Part 60, Appendix A, Method 19.

2.2.2 When the NO_x continuous emission monitoring system uses CO_2 as the diluent, use the following conversion procedure:

$E=CF_c[100/\text{percent } CO_2]$ (Eq. 2–4)

where E, C, Fc, and percent CO_2 are defined in Section 2.2.3.

2.2.3 Use the definitions listed below to derive values for the parameters in Equations 2–3 and 2–4.

2.2.3.1 E = pollutant emissions, lb/mmBtu.

2.2.3.2 C = pollutant concentration, lb/dscf, determined by multiplying the average concentration (ppm) for each 1-hr period by 1.19×10^{-7} lb/dscf per ppm.

2.2.3.3 Percent O_2, percent CO_2 = oxygen or carbon dioxide volume (expressed as percent).

2.2.3.4 F, F_c = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of CO_2 generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows.

2.2.3.4.1 For anthracite coal as classified according to ASTM D388–90 (incorporated by reference under § 75.9), F = 10,100 dscf/mmBtu and F_c = 1,970 scf CO_2/mmBtu.

2.2.3.4.2 For subbituminous and bituminous coal as classified according to ASTM D388–90 (incorporated by reference under § 75.9), F = 9,780 dscf/mmBtu and F_c = 1,800 scf CO_2/mmBtu.

2.2.3.4.3 For liquid fossil fuels including crude, residual, and distillate oils, F = 9,190 dscf/mmBtu and F_c = 1,420 scf CO_2/mmBtu.

2.2.3.4.4 For gaseous fossil fuels, F = 8,710 dscf/mmBtu. For natural gas, propane, and butane fuels, F_c = 1,040 scf CO_2/mmBtu for natural gas, 1,190 scf CO_2/mmBtu for propane, and 1,250 scf CO_2/mmBtu for butane.

2.2.3.4.5 For bark, F = 9,600 dscf/mmBtu and F_c = 1,920 scf CO_2/mmBtu. For wood residue other than bark, F = 9,240 dscf/mmBtu and F_c = 1,830 scf CO_2/mmBtu.

2.2.3.4.6 For lignite coal as classified according to ASTM D388–77 (incorporated by reference under § 75.9), F = 9,860 dscf/mmBtu and F_c = 1,910 scf CO_2/mmBtu.

2.2.3.5 Equation 2–5 may be used in lieu of the F or F_c factors specified in section 2.2.3.4 to calculate an F factor (dscf/mmBtu) on a dry basis or an F_c factor (scf CO_2/mmBtu) on either a dry or wet basis. (Consult the Administrator for a method to calculate an F factor on a wet basis).

$$F=\frac{3.64(\%H)+1.53(\%C)+0.57(\%S)+0.14(\%N)-0.46(\%O)}{GCV}\times10^6$$

$$F_c=\frac{321\times10^3(\%C)}{GCV} \qquad \text{(Eq. 2–5)}$$

2.2.3.5.1 H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as the gross calorific value (GCV) by ultimate analysis of the fuel combusted using ASTM D3176 (solid fuels) or computed from results using D1945–81 or D1946–90 (gaseous fuels) as applicable. (These three methods are incorporated by reference under § 75.9.)

2.2.3.5.2 GCV is the gross calorific value (Btu/lb) of the fuel combusted determined by ASTM D2015–85 for solid fuels and D1826–88 for gaseous fuels, as applicable. (These two methods are incorporated by reference under § 72.9).

2.2.3.5.3 For affected units that combust both fossil and nonfossil fuels, the F or F_c value shall be subject to the Administrator's approval.

2.2.3.6 For affected units that combust combinations of fossil fuels or fossil fuels and wood residue, the F or F_c factors determined by Section 2.3.4 shall be prorated in accordance with the applicable formula as follows:

$$F=\sum_{i=1}^{n} X_iF_i$$

$$F_c = \sum_{i=1}^{n} X_i (F_c)_i \qquad \text{(Eq. 2–6)}$$

where:

X_i=Fraction of total heat input derived from each type of fuel (e.g., natural gas, bituminous coal, wood).
F_i or $(F_c)_i$=Applicable F or F_c factor for each fuel type determined in accordance with Section 2.2.3.4.
n=Number of fuels being combusted in combination.

2.2.4 Use the following equations to calculate the NO_x emission rate for each calendar quarter (Eq. 2–7) and the annual average emission rate (Eq. 2–8) in lb/mmBtu.

$$E_q = \sum_{i=1}^{n} \frac{E_i}{n} \qquad \text{(Eq. 2–7)}$$

where:

E_q=Quarterly NO_x emission rate, lb/mmBtu.
E_i=Hourly NO_x emission rate, lb/mmBtu.
n=Number of hourly rates available in the preceding quarter.

$$E_a = \sum_{i=1}^{m} \frac{E_q}{m} \qquad \text{(Eq. 2–8)}$$

where:

E_a=Annual NOx emission rate, lb/mmBtu.
E_q=Quarterly NOx emission rate, lb/mmBtu.
m=Number of quarters for which E_q are available.

2.2.5 Round all NO_x emission rates to the nearest 0.001 lb/mmBtu.

2.3 CO_2. Use the following procedures to compute daily, quarterly, and annual CO_2 emissions in tons.

2.3.1 For an affected unit using a continuous emission monitoring system for the measurement of CO_2 emissions where CO_2 concentration is measured on a wet basis, use the following equation to calculate hourly CO_2 emission rates (in lb/hr).

$$E_h = K\, C_h\, Q_h \qquad \text{(Eq. 2–9)}$$

where:

E_h=Hourly emission rate of CO_2, lb/hr.
K=1.140 x 10^{-7} for CO_2, (lbs/scf)/ppm.
C_h=Hourly average CO_2 concentration, stack moisture basis, ppm.
Q_h=Hourly average volumetric flow rate, stack moisture basis, scfh.

Where CO_2 concentration is measured on a dry basis, use Equation 2–2 above to calculate the hourly CO_2 emission rate (in lb/hr) with a K-value of 1.14 x 10^{-7} (lb/scf)/ppm.

2.3.2 For an affected unit using a continuous emission monitoring system for the measurement of CO_2 emissions, use the following equation to calculate total CO_2 emissions for each calendar quarter in proportion to the recorded hourly CO_2 emissions.

$$E_{CO2} = E_R \times \frac{H_U}{H_R} \qquad \text{(Eq. 2–10)}$$

where:

E_{CO2}=Total emissions of CO_2 for calendar quarter, tons.
E_R=Total emissions of CO_2 recorded by the CO_2 continuous emission monitoring system for calendar quarter, tons.
H_U=Total unit operating hours for calendar quarter, hr.
H_R=Total unit operating hours for which the CO_2 continuous emission monitoring system recorded data for calendar quarter, hr.

2.3.3 For an affected unit estimating CO_2 emissions in lieu of continuous monitoring, use the following equation to calculate daily CO_2 emission rates from fuel combustion (in tons/day).

$$W_{CO2} = \frac{[MW_C + MW_{O2}] \times W_C}{MW_c} / 2{,}000 \qquad \text{(Eq. 2–11)}$$

where:

$W_{CO2=CO2}$ emitted from combustion, tons/day.
MW_C=Molecular weight of carbon (12.0).
MW_{O2}=Molecular weight of oxygen (32.0)
W_C=Carbon burned, lb/day, determined using fuel analysis by ASTM D3178–(89) for coal; or determined by the percentage of carbon in oil from the ultimate analysis of oil, or computed based upon ASTM D3238–(85) and either ASTM D2502–(87) or ASTM D2503–(82) for oil; or computed based on ASTM D1945–(81) or ASTM D1946–(90) for gas; and fuel feed rates from company records for all fuels.

Sum the daily CO_2 emissions to obtain total CO_2 emissions for each calendar quarter and annual CO_2 emissions.

2.3.4 If the affected unit is equipped with a wet limestone flue gas desulfurization system, a fluidized bed with limestone as the sorbent material, or other emission control system that generates CO_2, use the following equation to calculate daily CO_2 emissions from the emission control system (in tons/day).

$$SE_{CO2} = W_{CaCO3} \times F_u \times [MW_{CO2}/MW_{CaCO3}] \qquad \text{(Eq. 2–12)}$$

where:

SE_{CO2}=CO_2 emitted from sorbent, tons/day.
W_{CaCO3}=$CaCO_3$ used, tons/day.
F_u=Sorbent utilization factor, 1.07 (the calcium to sulfur stoichiometrc ratio). A value of 1.07 is used unless a different factor is calculated by the emissions control vendor or the owner or operator based on operational parametric conditions, and approved by the Administrator.
MW_{CO2}=Molecular weight of carbon dioxide (44).
MW_{CaCO3}=Molecular weight of calcium carbonate (100).

2.3.5 For an affected unit equipped with an emissions control system that generates CO_2, use the following equation to obtain total daily CO_2 emissions (in tons/day) by adding the estimates of daily CO_2 emissions from fuel combustion and from the sorbent.

$$W_t = W_{CO2} + SE_{CO2} \qquad \text{(Eq. 2–13)}$$

where:

W_t=Estimated total CO2 emissions, tons/day.
W_{co2}=CO_2 emitted from fuel combustion, tons/day.
SE_{co2}=CO_2 emitted from sorbent, tons/day.

Sum the daily CO_2 emissions to obtain total CO_2 emissions for each calendar quarter and annual CO_2 emissions.

2.4 Heat Input. Use the following procedures to compute heat input to an affected unit (in mmBtu).

2.4.1 Calculate and record heat input to an affected unit from any fuel other than natural gas on an hourly basis and from natural gas for each shipment delivered.

2.4.2 For an affected unit that has a flow monitor and a diluent gas (O_2 or CO_2) monitor, use the recorded data from these monitors and one of the following equations to calculate hourly heat input (in mmBtu).

2.4.2.1 For CO_2 diluent monitors that measure CO_2 concentration on a wet basis, use the following equation:

$$HI = Q_w \times (1/F_c) \times (\%CO_{2w}/100) \qquad \text{(Eq. 2–14)}$$

where:

HI=Hourly heat input, mmBtu.
Q_w=Hourly volumetric flow rate, wet basis, scfh.
F_c=Carbon-based F-factor, listed in Section 2.2.3.4 of this appendix for each fuel, scf/mmBtu.
$\%CO_{2w}$=Hourly concentration of CO_2, percent wet basis.

2.4.2.2 For CO_2 diluent monitors that measure CO_2 concentration on a dry basis, use the following equation:

$$HI = Q_w \times (1 - B_{ws})/F_c \times (\%CO_{2d}/100) \qquad \text{(Eq. 2–15)}$$

where:

HI=Hourly heat input, mmBtu.

Q_w=Hourly volumetric flow rate, wet basis, scfh.

F_c=Carbon-based F-factor, listed above in 2.2.3.4 of this appendix for each fuel, scf/mmBtu.

$\%CO_{2d}$=Hourly concentration of CO_2, percent dry basis.

B_{ws}=Moisture fraction of gas in the stack.

2.4.2.3 For O_2 diluent monitors that measure O_2 concentration on a set basis, use the following equation:

$$HI=Q_w\times(1/F_d)\times[20.9(1-B_{ws})-\%O_{2w}]/20.9 \quad \text{(Eq. 2-16)}$$

where:

HI=Hourly heat input, mmBtu.

Q_w=Hourly volumetric flow rate, wet basis, scfh.

F_d=Dry basis F-factor, listed above in 2.2.3.4 of this appendix for each fuel, dscf/mmBtu.

$\%O_{2w}$=Hourly concentration of O_2, percent wet basis.

B_{ws}=Moisture fraction of the stack gas.

2.4.2.4 For O_2 diluent monitors that measure O_2 concentration on a dry basis, use the following equation.

$$HI=[Q_w\times(1-B_{ws})/F_d]\times[(20.9-\%O_{2d})/20.9] \quad \text{(Eq. 2-17)}$$

where:

HI=Hourly heat input, mmBtu.

Q_w=Hourly volumetric flow, wet basis, scf.

F_d=Dry basis F-factor, listed above in 2.2.3.4 of this appendix for each fuel, dscf/mmBtu.

B_{ws}=Moisture fraction of the stack gas.

$\%O_{d2}$=Hourly concentration of O_2, percent dry basis.

2.4.3 Use the procedures specified in § 75.13(e) of this part to provide substitute data whenever a valid hour of flow data has not been obtained and recorded.

2.4.4 Whenever a valid hour of diluent (O_2 or CO_2) concentration has not been obtained and recorded, substitute for each hour in each missing data period the average of the recorded diluent gas (O_2 or CO_2) percentage concentration for the hour immediately before and the hour immediately following the missing data period.

2.4.5 For an affected unit that does not have a flow monitor and is using the procedures specified in appendix D of this part to monitor SO_2 emissions, use the following procedures to calculate hourly heat input in mmBtu.

2.4.5.1 Use the following equation to calculate hourly heat input when the unit is combusting oil.

$$HI_o=M_o\times GCV_o/1{,}000{,}000 \quad \text{(Eq. 2-18)}$$

where:

HI_o=Hourly heat input from oil, mmBtu.

M_o=Mass of oil consumed per hour, as determined using procedures in appendix D of this part, i lb, tons, or kg.

GCV_o=Gross calorific value of oil, as measured daily by ASTM D240–87 or D2382–88, Btu/unit mass.

2.4.5.2 Use the following equation to calculate the heat input from each shipment of natural gas.

$$HI_g=(Q_g\times GCV_g)/1{,}000{,}000 \quad \text{(Eq. 2-19)}$$

where:

HI_g=Heat input of shipment of natural gas, mmBtu.

Q_g=Flow or amount of natural gas in shipment, scf.

GCV_g=Gross calorific value of natural gas, as measured for the shipment by ASTM D1826–88, Btu/scf.

BILLING CODE 6560-50-M

Draft -- October 28, 1991

Appendix F to Part 75--Continuous Emission Monitoring Forms

FIGURE 1
EXAMPLE DAILY UNIT OPERATING DATA

HOURLY OPERATING DATA						
Hour	Unit Operating Time hr	Total Heat Input mmBtu	Integrated Gross Unit Load MWge	Operating Load Range[1]	Fuel Sulfur Content %[2]	Sulfur Content Range[3]
01						
02						
03					Record for each 6-hr period	
04						
.						
.						
24						
Total						

1 Use codes for Operating Load Range in Appendix C, Section 3.
2 Record on a six-hour basis. Denote beginning and ending hours of each six-hour period.
3 Use codes for Sulfur Content Range in Appendix C, Section 4.

Draft -- October 22, 1991

FIGURE 2
EXAMPLE DAILY SO_2 EMISSIONS AND FLOW RECORD

DAILY MONITOR OPERATION DATA

Date	SO_2 Monitor					Flow Monitor				
	% Monitor Availability	% Calibration Error		Total Hours Out-of-Control[1]	Bias Adjustment Factor	% Monitor Availability	% Calibration Error		Total Hours Out-of-Control[2]	Bias Adjustment Factor
		Low	High				Low	High		

HOURLY SO_2 EMISSIONS AND FLOW DATA

Hour	Average SO_2 Concentration		Method of Emissions Determination[3]	Measured Average Flow Rate scfh	Adjusted Average Flow Rate scfh	Average Stack Moisture %, by vol	Method of Flow Rate Determination[4]	SO_2 Emissions Rate	
	Measured ppm	Adjusted ppm						Measured lb/hr	Adjusted lb/hr
01									
02									
03									
.									
.									
24									
Total									

1 If daily calibration error is greater than 5%, SO_2 monitor is deemed to be out-of-control.

2 If daily calibration error is greater than 6%, flow monitor is deemed to be out-of-control.

3 Codes for Method of SO_2 Concentration Determination:

1 - Primary monitor
2 - Backup/portable monitor
3 - Alternative monitoring system
4 - Method 6, 6A, 6B or 6C
5 - Average hour before and after
6 - 90th percentile hourly concentration 30 days
7 - 90th percentile hourly concentration 365 days
8 - Preapproved parametric monitoring or correlation method
9 - Other (attach description)

4 Codes for Method of Flow Rate Determination:

1 - Primary monitor
2 - Backup/portable monitor
3 - Alternative monitoring system
4 - Method 2
5 - Average hourly flow rate 30 days
6 - 90th percentile hourly flow rate 30 days
7 - 90th percentile hourly flow rate 365 days
8 - Other (attach description)

Draft -- October 22, 1991

FIGURE 3
EXAMPLE DAILY NO_x AND CO_2 EMISSIONS RECORDS

DAILY MONITOR OPERATION DATA

Date	NO_x Monitoring System							CO_2 Monitor (if used)					
	% System Availability	NO_x % Calibration Error		Diluent % Calibration Error		Total Hours Out-of-Control[1]	Bias Adjustment Factor	% Monitor Availability	% Calibration Error		Total Hours Out-of-Control[2]	Bias Adjustment Factor

HOURLY NO_x EMISSIONS AND DAILY CO_2 EMISSIONS DATA

Hour	Average NO_x Emissions			Method of Emissions Rate Determination[2]	Daily CO_2 Emissions lb
	ppm	Measured Rate lb/mmBtu	Adjusted Rate lb/mmBtu		
01					
02					
03					
.					
.					
.					
24					
Total					

1 If daily calibration error is greater than 5%, the monitor is deemed to be out-of-control.

2 Codes for Method of NO_x Emissions Rate Determination:

1 - Primary monitoring system
2 - Backup/portable monitoring system
3 - Alternative monitoring system
4 - Method 7, 7A, 7B, 7C, 7D or 7E
5 - Preapproved parametric monitoring or correlation method
6 - Average hourly rate (lb/mmBtu) 365 days
7 - 90th percentile hourly rate 30 days
8 - 90th percentile hourly rate 365 days
9 - Other (attach description)

Draft -- October 22, 1991

FIGURE 4
SUPPLEMENTARY SO_2 EMISSION CONTROL OPERATION INFORMATION FOR MISSING DATA PERIODS[1]

HOURLY CONTROL EQUIPMENT OPERATION DATA								
		All Scrubbers					Wet FGD	Dry FGD
Date	Hour	Number of Scrubber Modules in Operation	Average Slurry % Solids	Slurry Feed Rate gal/min	Average Pressure Differential in/wc[2]	Estimated % SO_2 Removal Efficiency	Average Inline Absorber pH	Dew Point Approach Temperature °F
To Be Completed Only for Hours for Which a Substitute SO_2 Emission Data Determination Method (Codes 4-9) Is Used								

1 Information to be submitted by units equipped with SO_2 emission controls for each hour during which SO_2 emission determinations are not available from primary, back-up, or approved alternative monitoring systems.

2 Inches of water column.

Draft -- October 22, 1991

FIGURE 5

SUPPLEMENTARY NO_x EMISSION CONTROL OPERATION INFORMATION FOR MISSING DATA PERIODS[1]

HOURLY CONTROL EQUIPMENT OPERATION DATA						
Date	Hour	Inlet Air Flow Rate scfh	Excess Oxygen %	CO Concentration Stack Outlet ppm	Outlet Flue Gas Temperature °F	Other Parameter[2]
To Be Completed Only for Hours for Which a Substitute NO_x Emission Data Determination Method (Codes 4-9) Is Used						

1 Information to be submitted by units equipped with post-combustion NO_x emission controls for each hour during which NO_x emission determinations are not available from primary, back-up, or approved alternative monitoring systems.

2 Parameters specific to post-combustion NO_x emissions reduction process. Specify other parameters reported.

FIGURE 6

DRAFT 7510
Date 10/25/91
Please print or type in the unshaded areas only.

ARP Unit ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Monitoring Plan

Follow "7510" Instruction packet in completing this form. Note: Phase I units must submit monitoring plan no later than the date of submission of the permit application; Phase II units must submit monitoring plan no later than the request for monitoring certification. Submit a revised copy of this form if any of the information that you report below changes.

I. UNIT IDENTIFICATION

A. Unit Information

1. Unit ARP ID Number
2. Short Name

B. Facility Information

1. Source or Facility Name
2. Street or P.O. Box
3. City
4. State
5. Zip –

C. Contact for Monitoring Information

1. Contact Name
2. Phone *(area code & number)* – –

II. BOILER INFORMATION

A. Identify this unit's boiler type(s):

☐ 1. Tangentially fired ☐ 2. Dry bottom wall-fired ☐ 3. Wet bottom wall-fired ☐ 4. Cyclone ☐ 5. Applying cell burner technology

☐ 6. Other:

B. Date of initial boiler operation *(mm/dd/yy)*: →

C. Estimated annual operation *(hours)*: →

III. FUEL INFORMATION

Fuel	Estimated Annual % of Use *(Btu)*	Estimated Sulfur of Fuel *(lbs/mmBtu)*	Fuel	Estimated Annual % of Use *(Btu)*
A. Coal			D. Wood	
B. Oil			E. Refuse	
C. Natural Gas			F. Other	

IV. CONTROL EQUIPMENT

A. SO_2

☐ 1. Uncontrolled ☐ 2. Dry Lime FGD ☐ 3. Wet Limestone FGD

☐ 4. Other:

B. NO_x

☐ 1. Uncontrolled ☐ 2. Low NO_x Burner Technology

☐ 3. Other: ☐ a. Combustion ☐ b. Post Combustion

(Describe):

C. Particulates

☐ 1. Uncontrolled ☐ 2. Baghouse(s) ☐ 3. ESP

☐ 4. Other:

V. STACK INFORMATION

A. Inside Stack Diameter at Monitor Location →

B. Height →

FIGURE 6

Please print or type in the unshaded areas only.

ARP Unit ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

VI. COMMON STACK ELECTION

A. Does this unit share a common stack with other units?

☐ No. If no, complete sections VII - XI ☐ Yes. If yes, submit form 7512 and see VI.B.

B. If this unit is the Primary Unit for the stack, identify Primary ARP Unit →

C. Primary Unit ARP ID No. [from form 7512]

D. Short Name

E. Number of Units Sharing Monitor *(to be completed only for combined stacks)*:

Monitor Type	Number of Units	Monitor Type	Number of Units	Monitor Type	Number of Units
1. SO_2 Outlet		3. Volumetric Flow		5. Diluent	
2. NO_x		4. Moisture		6. Opacity	

VII. SO_2 INLET MONITORING EQUIPMENT (if required)

A. Pollutant

1. Manufacturer:
2. Model #:
3. Type: ☐ a. In situ ☐ b. Extractive ☐ c. Dilution ☐ d. Other
4. Installation Date *(mm/yy)*:
5. Type Description:
6. Backup System:

☐ 7. Approved Alternate in Use ☐ 8. Siting Information Attached

☐ Test report of CEMS certification is attached. If it is not, report will be submitted by *(mm/dd/yy)* →

B. Diluent

1. Manufacturer:
2. Model #:
3. Type: ☐ a. In situ ☐ b. Extractive ☐ c. O_2 ☐ d. CO_2 ☐ e. Other
4. Installation Date *(mm/yy)*:
5. Type Description:
6. Backup System:

☐ 7. Approved Alternate in Use ☐ 8. Siting Information Attached

☐ Test report of CEMS certification is attached. If it is not, report will be submitted by *(mm/dd/yy)* →

VIII. SO_2 OUTLET MONITORING EQUIPMENT

A. Pollutant

1. Manufacturer:
2. Model #:
3. Type: ☐ a. In situ ☐ b. Extractive ☐ c. Dilution ☐ d. Other
4. Installation Date *(mm/yy)*:
5. Type Description:
6. Backup System:

☐ 7. Approved Alternate in Use ☐ 8. Siting Information Attached

☐ Test report of CEMS certification is attached. If it is not, report will be submitted by *(mm/dd/yy)* →

B. Volumetric Flow

1. Manufacturer:
2. Model #:
3. Type: ☐ a. Differential Pressure ☐ b. Ultrasonic ☐ c. Thermal ☐ d. Other
4. Installation Date *(mm/yy)*:
5. Type Description:
6. Backup System:

☐ 7. Approved Alternate in Use ☐ 8. Siting Information Attached

☐ Test report of CEMS certification is attached. If it is not, report will be submitted by *(mm/dd/yy)* →

NOTE: SECTION VIII SO_2 OUTLET MONITORING EQUIPMENT is continued on Page 3 of this form →

FIGURE 6

Please print or type in the unshaded areas only.

ARP Unit ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

VIII. SO_2 OUTLET MONITORING EQUIPMENT (cont.)

C. Moisture (if applicable)

1. Manufacturer:		2. Model #:	
		3. Installation Date(mm/yy):	
4. Backup System:			

☐ 5. Approved Alternate in Use ☐ 6. Siting Information Attached

IX. NO_x MONITORING EQUIPMENT

A. Pollutant

1. Manufacturer:		2. Model #:	
3. Type:	☐ a. In situ ☐ b. Extractive ☐ c. Other	4. Installation Date(mm/yy):	
5. Type Description:			
6. Backup System:			

☐ 7. Approved Alternate in Use ☐ 8. Siting Information Attached

☐ Test report of CEMS certification is attached. If it is not, report will be submitted by (mm/dd/yy) ⟶

B. Diluent

1. Manufacturer:		2. Model #:	
3. Type:	☐ a. In situ ☐ b. Extractive ☐ c. O_2 ☐ d. CO_2 ☐ e. Other	4. Installation Date(mm/yy):	
5. Type Description:			
6. Backup System:			

☐ 7. Approved Alternate in Use ☐ 8. Siting Information Attached

☐ Test report of CEMS certification is attached. If it is not, report will be submitted by (mm/dd/yy) ⟶

X. OPACITY MONITORING EQUIPMENT

1. Manufacturer:		2. Model #:	
		3. Installation Date(mm/yy):	
4. Backup System:			

☐ 5. Approved Alternate in Use ☐ 6. Siting Information Attached

☐ 7. This unit submits excess emissions reports to:

(Name of State or Local Agency)

XI. DATA ACQUISITION SYSTEM

A. Hardware Components

☐ Additional Information Attached

Item	Manufacturer	Model #	Actual or Projected Installation Date (mm/dd/yy)
1			
2			
3			
4			
5			

NOTE: SECTION XI DATA ACQUISITION SYSTEM is continued on Page 4 of this form ⟶

FIGURE 6

Please print or type in the unshaded areas only.

ARP Unit ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

XI. DATA ACQUISITION SYSTEM (cont.)

B. Software Components ☐ Additional Information Attached

Item	Provider	Customized?	Description
1			
2			
3			
4			
5			

☐ Data Flow Diagram and Equations Attached

C. Backup Plan - Systems

D. Backup Plan - Procedures

E. Primary DAS Contact

1. Contact Name

2. Phone *(area code & number)* - -

XII. CERTIFICATION

I certify under penalty of law that I personally have examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of EPA Approved Designated Representative	B. DR ID Number
C. Signature	D. Date Signed

FOR EPA USE ONLY

1. Date Received: ______
2. Date of Initial Review: ______ By: ______
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: ______
3. Date of Final Approval: ______ By: ______
4. Date Notice Sent: ______ By: ______

Comments:

FIGURE 7

DRAFT 7512
Date 10/25/91

Please print or type in the unshaded areas only.

ARP Facility ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Monitoring Plan -- Common Stack Information

Follow "7512" instruction packet in completing this form.

I. FACILITY IDENTIFICATION

Source or Facility Name

II. UNIT IDENTIFICATIONS

Identify the primary unit at A.1.

	A. Unit ARP ID Number	B. Short Name	C. Classification				
			Phase I	Phase II	New	Opt-In	Non-Affected
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							

☐ Schematic diagram attached.

III. SO_2 EMISSIONS

UNIT	Single Combined Stack Monitor Combined Allowances		Separate Duct Monitoring for Each Unit	Emissions from Common Stack Monitor Apportioned by Approved Alternative Method	Common Stack Monitor Emissions Minus Emissions from Monitored Non-affected Unit	Emissions Data from this Unit to be Subtracted from Common Stack Monitor Emissions
	Yes	Allowance				
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
Total Allowance →						

FIGURE 7

ARP Facility ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

Please print or type in the unshaded areas only.

IV. NO_x EMISSIONS

UNIT	Nox Standard	Same Standard Applied for all Units	Most Stringent Standard Applied	Common Stack Monitor: Nitrogen Oxides Averaging Plan	Common Stack Monitor: Approved Alternative Method to Apportion Emissions	Common Stack Monitor: Will Subtract Emissions from Monitored Non-affected Unit	Common Stack Monitor: Emissions Data from this Unit to be Subtracted from Common Stack Monitor Emissions	Separate Nox Monitor for Unit in Ducts
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								

V. CERTIFICATION

I certify under penalty of law that I personally have examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of EPA Approved Designated Representative

B. DR ID Number

C. Signature

D. Date Signed

FOR EPA USE ONLY

1. Date Received: ____
2. Date of Initial Review: ____ By: ____
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: ____
3. Date of Final Approval: ____ By: ____
4. Date Notice Sent: ____ By: ____

Comments:

DRAFT - OCTOBER 25, 1991 /512/pg.2

BILLING CODE 6560-50-C

PART 77—EXCESS EMISSIONS

Authority: 42 U.S.C. 7651.

PART 77—EXCESS EMISSIONS

§ 77.0 Applicability.

(a) General. This part sets forth the Acid Rain excess emissions offset planning and offset penalty requirements pursuant to section 411 of the Clean Air Act, 42 U.S.C. 7401, et seq. as amended by Public Law 101-549 (November 15, 1990) (the Act). These requirements shall apply to the affected units and affected sources, and to the owners, operators, and designated representative of each affected unit or source under the Acid Rain program, as specified in 40 CFR 72.7 and 72.21.

(b) Requirements and prohibitions of designated representatives, owners, and operators. Whenever any standard, requirement, or prohibition in this part or in 40 CFR parts 70 through 78 applies to an affected unit or an affected source, or to the designated representative of an affected unit or affected source, the standard, requirement, or prohibition shall also apply to and be binding on each and every owner and operator of the affected unit or source (as applicable), each of whom shall be liable for any violation of such standard, requirement, or prohibition.

(c) Nothing in this part shall limit or otherwise affect the application of sections 112(r)(9), 113, 114, 120, 303, 304, or 306 of the Act, as amended.

§ 77.1 Definitions.

For purposes of this part, the terms shall have the same meaning as that given in the Act, in 40 CFR parts 72 through 78, and in this section, as follows:

Acid Rain compliance option means one of the following methods of compliance used by an affected unit under this part as described in a compliance plan submitted and approved in accordance with subpart D of this part:

(1) Standard sulfur dioxide compliance method: having total emissions in any calendar year that are not greater than the allowances held, as of the allowance transfer deadline, in the unit's compliance subaccount for that year in accordance with a plan submitted and approved under § 72.40(b);

(2) Standard nitrogen oxides compliance method: emitting nitrogen oxides from an affected unit during a calendar year in an amount not greater than allowed by the applicable emissions limitation for the unit, pursuant to 40 CFR part 76, in accordance with a plan submitted and approved under § 72.40(b);

(3) Compliance with a substitution plan submitted and approved in accordance with § 72.41;

(4) Compliance with a Phase I extension plan submitted and approved in accordance with § 72.42;

(5) Compliance with a reduced utilization plan submitted and approved in accordance with § 72.43;

(6) Compliance with a repowering extension plan submitted and approved in accordance with § 72.44;

(7) Compliance with a nitrogen oxides emissions averaging plan submitted and approved in accordance with § 72.46;

(8) Compliance with a nitrogen oxides alternative emissions limitation plan submitted and approved in accordance with § 72.47;

(9) Compliance with a nitrogen oxides compliance deadline extension plan submitted and approved in accordance with § 72.48;

(10) Compliance with a new unit plan submitted and approved in accordance with § 72.45;

(11) Compliance with an opt-in plan submitted and approved in accordance with § 72.49; or

(12) Compliance with a common-stack plan submitted and approved in accordance with § 72.50.

Acid Rain permit or permit means a permit, or the Acid Rain portion of a permit under 40 CFR parts 70 or 71, including an approved compliance plan, issued by the Administrator or other permitting authority pursuant to this part and 40 CFR parts 73 through 78 after completion of all administrative review.

Acid Rain program means the sulfur dioxide and nitrogen oxides air pollution control program established pursuant to title IV of the act under 40 CFR parts 72 through 78.

Act means the Clean Air Act, 42 U.S.C. 7401, et seq., as amended by Public Law No. 101-549 (November 15, 1990).

Administrative permit amendment means a revision of an Acid Rain permit pursuant to § 72.303.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

Affected source means a source that includes one or more affected units.

Affected unit means a unit, or a source that opts-in under 40 CFR part 74, that is subject to any emission reduction requirement or limitation under the Acid Rain program.

Allowance means an authorization, allocated by the Administrator under the Acid Rain program to emit, during or after a specified calendar year, up to one ton of sulfur dioxide.

Allowance Tracking System means the system by which the Administrator issues, records, and tracks allowances.

Allowance transfer deadline means midnight of January 30 or, if January 30 is not a business day, midnight of the first business day thereafter, which is the last day on which allowances may be submitted for recordation in an affected unit's compliance subaccount for the purposes of meeting sulfur dioxide emissions limitation requirements for the previous calendar year.

Approved compliance plan means a compliance plan, and any revision thereto, that has been approved as part of an Acid Rain permit by the Administrator or the permitting authority in accordance with this part.

Calendar year means January 1 through December 31, inclusive.

Certificate of representation means the completed and signed submission, using the standard form required by § 72.20, for certifying the appointment of a designated representative for an affected source, an affected unit, or a group of identified affected units.

Compensating unit means a unit that is not otherwise an affected unit during Phase I, which is designated as an affected unit during Phase I for the purposes of providing electrical generation to make up for reduced utilization at one or more other Phase I affected units, in accordance with § 72.43.

Compliance plan means the permit document, submitted in accordance with subparts C and D of Part 72, certifying that the source will comply with all applicable requirements under the Acid Rain program and including a schedule of compliance and description of the Acid Rain compliance options by which each unit at the source will meet the applicable emissions limitation requirements of title IV of the Act.

Compliance subaccount means an affected unit's allowance tracking

system subaccount in which are held, from the date that allowances for the current calendar year are recorded under § 73.34(a) until December 31, allowances for the current calendar year and, after December 31 until the date that deductions are made under § 73.35(b), allowances for the preceding calendar year.

Consumer Price Index (CPI) means the United States government's primary indicator of the monetary inflation rate as published monthly by the U.S. Department of Labor, Bureau of Labor Statistics Consumer Price Index Branch, in the CPI Detailed Report and in the Monthly Labor Review. For purposes of this part, the Administrator will use the Consumer Price Index for all urban consumers for the US City Average, for all Items on the Official Reference Base (CPI-U), or if such index is no longer published, such other index as the Administrator in his discretion determines meets the requirements of the Clean Air Act Amendments of 1990. For the purposes of this part, the CPI-U is based on the twelve month period ending August 31.

Designated representative means the natural person authorized by the owners and operators of an affected source and of all affected units at the source, as evidenced by a certificate of representation submitted in accordance with 40 CFR part 72, Subpart B, to represent and legally bind each owner and operator, as a matter of Federal law, in all matters pertaining to the Acid Rain program. Except in § 72.20(c), the term designated representative shall also mean any natural person authorized in accordance with § 72.20(c) of 40 CFR part 72 as an alternate designated representative. Whenever the term responsible official is used in 40 CFR part 70 or part 71 or in a State operating permit program approved pursuant to title V of the Act and 40 CFR part 70, it shall be deemed to refer to the designated representative as defined here in so far as Acid Rain program actions, standards, requirements, or prohibitions are concerned.

Determination of completeness means a finding by a permitting authority in accordance with § 72.72 or § 70.5(c) with regard to an Acid Rain permit program application specifying that the application contains all the information needed to begin processing the application, consistent with the criteria in subpart G of this part.

Emissions means the quantity of an air pollutant emitted from an affected unit, as measured, recorded, and reported to the Administrator or a State by the designated representative and determined by the Administrator, in accordance with the emissions monitoring requirements of 40 CFR part 75.

Emissions limitation means (1) For the purposes of sulfur dioxide emissions, the tonnage equivalent of:

(i) The allowances allocated by the Administrator to a unit for use in a calendar year, in accordance with an Acid Rain permit application submitted to the permitting authority and consistent with the requirements of title IV of the Act and the Acid Rain program, or with the Acid Rain permit issued by the permitting authority;

(ii) As amended by allowance transfers to or from the compliance subaccount for that unit.

(2) For purposes of nitrogen oxides emissions, the limitation established pursuant 40 CFR part 76, in accordance with an Acid Rain permit application submitted to the permitting authority and consistent with the requirements of title IV of the Act and the Acid Rain program, or with an Acid Rain permit issued by the permitting authority.

EPA means the United States Environmental Protection Agency or, for purposes of 40 CFR part 73, any person who by delegation or contract is managing and conducting the auctions and direct sales provided in part 73 on behalf of EPA.

Excess emissions means: (1) Any tonnage emissions of sulfur dioxide by an affected unit during a calendar year that exceeds the sulfur dioxide allowances recorded in the unit's compliance subaccount; and

(2) Any tonnage emissions of nitrogen oxide by an affected unit during a calendar year that exceed the emissions limitation applicable to the affected unit as specified in 40 CFR part 76 and the affected unit's permit.

Offset period means the calendar year, or such other period, as determined by the Administrator in accordance with 40 CFR part 77, following a calendar year in which an affected unit had excess emissions, during which excess emissions offsets are required to be achieved.

Offset plan means a plan submitted and approved pursuant to 40 CFR part 77 for offsetting excess emissions that have occurred at an affected unit in any calendar year.

Owner means any of the following persons, each of which is required to be identified in a certificate of representation under 40 CFR part 72, subpart B:

(1) Any holder of any portion of the legal or equitable title to an affected unit; or

(2) Any holder of a leasehold interest in an affected unit; or

(3) Any utility or industrial customer that purchases power from an affected unit under a life-of-the-unit, firm power contractual arrangement as that term is used in section 408(i) of the Act. However, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based, either directly or indirectly, upon the revenues or income from the affected unit.

Owner or operator means any person who is an owner or who operates, controls, or supervises an affected unit or a source of which an affected unit is a part, and shall include but not be limited to any holding company, operating company, utility system, designated representative, or plant manager of an affected unit or affected source.

Permitting authority means either of the following:

(1) The Administrator in the case of EPA implementation of the Acid Rain permit program; or

(2) The State air pollution control agency, local agency, other State agency, Indian tribe, or other agency authorized by the Administrator to issue proposed Acid Rain permits under title IV and V of the Act and 40 CFR part 70 and part 72, subpart I.

Person means an individual corporation, partnership, association, State, municipality, political subdivision of a State, and any agency, department, or instrumentality of the United States and any officer, agent, or employee thereof.

Phase I means the Acid Rain program compliance period beginning January 1, 1995 and ending December 31, 1999.

Schedule of compliance means an enforceable sequence of actions, measures, or operations designed to achieve or maintain compliance, or correct non-compliance, with an applicable requirement of the Act, including any applicable Acid Rain permit requirement.

Serial number means the unique identification number assigned to each allowance by EPA, pursuant to § 73.34(c).

Source means any institutional, commercial, or industrial structure, installation, plant, or building that emits or has the potential to emit any air pollutant regulated under title IV of the Act. For purposes of section 502(c) of the Act, a source, including a source with multiple units, shall be considered a single facility.

State means one of the 48 contiguous States and the District of Columbia, and includes all non-federal authorities,

including local agencies, interstate associations, tribal authorities, and state-wide agencies with approved permit programs under 40 CFR part 70. The term State also encompasses those Native American governing bodies that the Administrator has determined, pursuant to section 301(d) of the Act, to treat as States.

Substitution unit means an affected unit that is listed in 40 CFR part 72, appendix B and is designated as a Phase I affected unit in a substitution plan under § 72.41.

Sulfur dioxide emissions limitation requirements means the limitation specified for an affected unit in sections 403, 404, or 405 of the Act or in the unit's permit.

Ton or Tonnage means any ton or fraction of a ton of emissions. For the purpose of determining compliance with the allowance requirements of the Acid Rain program, any fraction of a ton shall be deemed to equal one ton and require one allowance.

Unit means a fossil-fuel fired combustion device that serves a generator.

Utilization means the heat input for a unit.

§ 77.2 Sulfur dioxide excess emissions offset planning.

(a) Applicability. The owners and operators of any affected unit that emits sulfur dioxide in any calendar year in an amount that exceeds the affected unit's Acid Rain program sulfur dioxide emissions limitation requirement for that year, based on the number of allowances held in the unit's Allowance Tracking System account as provided in 40 CFR part 73, shall compensate for such excess emissions during the offset period specified by the Administrator in accordance with this section, by an amount equal to or in excess of the tons of excess emissions that occurred during that year.

(b) Deadline. Not later than 60 days after the end of any calendar year during which excess emissions of sulfur dioxide occurred at an affected unit, the designated representative for the affected unit shall submit a proposed excess emissions offset plan to the Administrator, to the EPA Regional Office for the State where the source is located, to the permitting authority for the State in which the source is located, and to each State located within a 50-mile radius of an affected source. All submissions shall be made as provided in 40 CFR 72.4.

(c) Multi-Unit Plans—General Rule. Except as provided in paragraph (d) of this section, the designated representative for two or more affected units with excess emissions shall submit a separate excess emissions offset plan for each affected unit with excess emissions. The multi-unit plan shall consist of one SF #772 for each unit in the plan.

(d) Multi-Unit Plans—Exception. The designated representative for two or more affected units with excess emissions governed by a common stack plan approved pursuant to 40 CFR 72.50, shall submit one excess emissions offset plan for those affected units with excess emissions.

(e) Contents of Plan. Each proposed excess emissions offset plan submitted pursuant to this part shall be submitted on SF #772 in appendix A of this part, and shall:

(1) Be signed by the designated representative of the unit(s) governed by the plan;

(2) Specify the name, title, phone number, facsimile number, mailing address, and Acid Rain program identification number of the designated representative for the affected unit with excess emissions;

(3) Specify the name, location, mailing address, and Acid Rain program identification number of the affected unit with excess emissions;

(4) Include a certification that the affected unit had excess emissions for the calendar year:

(i) Specifying the number of tons of excess emissions emitted by the affected unit during the calendar year;

(ii) Describing how and why the excess emissions occurred; and

(iii) Describing any corrective actions that were taken by the owners and operators to prevent or minimize the extent of the excess emissions;

(5) Specify the proposed offset methodology, and a schedule for achieving the offsets, as follows:

(i) Each offset plan shall include a description of the measures that are proposed to be taken to offset the excess emissions including:

(A) The number of allowances required to be deducted from the unit's Allowance Tracking System account to offset the excess emissions; and

(B) A schedule of compliance with appropriate increments of progress for reducing emissions of sulfur dioxide; for deducting allowances to offset the excess emissions from the Allowance Tracking System account of the unit or units responsible under the plan for achieving the offsets, including the serial number of the allowances and specification of when the deduction should occur; for obtaining additional allowances necessary; and for taking corrective actions.

(ii) Each offset plan shall include a certification that no allowance will be transferred during the offset period from the Allowance Tracking System account for the affected unit responsible for the offsets that might cause any further excess emissions at the unit.

(iii) If the designated representative proposes to offset excess emissions using the standard offset method (i.e., deducting the entire amount of allowances equal to the tonnage of excess emissions from the unit's Allowance Tracking System compliance subaccount for the following calendar year), the offset plan shall so state.

(iv)(A) If the designated representative proposes to offset excess emissions occurring during Phase I by relying on one or more Acid Rain compliance options authorized under 40 CFR part 72, subpart D (e.g., 40 CFR 72.43, reducing utilization or shutting down the affected unit responsible for the excess emissions and offsets), the offset plan shall include the appropriate standard form for the Acid Rain compliance option plan chosen, as provided in 40 CFR part 72, subpart D.

(B) Each offset plan shall include a demonstration that the reductions achieved by relying on one or more Acid Rain compliance options of 40 CFR part 72, subpart D is equal to the reductions required by a standard excess emissions offset plan, in accordance with paragraph (e)(5)(iii) of this section.

(v) If the compliance option chosen involves multiple units, the offset plan shall include:

(A) A designation of any compensating or substitution unit(s);

(B) A schedule specifying deadlines for, e.g., reducing utilization of the unit responsible for the excess emissions, and for the load shifting; and

(C) A certificate of representation establishing each designated representative's authority with regard to each unit covered by the multi-unit plan.

(vi) If the designated representative proposes to offset excess emissions by installing a technological means of pollution control (e.g., high efficiency scrubber, repowering or other clean coal technology), the excess emissions offset plan shall:

(A) Specify increments of progress for installing and commencing operation of equipment; and

(B) Include a showing of technical adequacy.

(vii) Each offset plan shall include a demonstration that the schedule for achieving the offsets is as expeditious as practicable, taking into account electric reliability.

(6) List and describe the provisions of the affected unit's permit and approved compliance plan that would be revised by the proposed offset plan if approved;

(7) Include a schedule for the submission of progress reports, as follows:

(i) The offset plan shall require that the designated representative submit quarterly progress reports, submitted with the reports due under 40 CFR 72.401(b), commencing with the first calendar quarter following the date in which an excess emissions offset plan is due under paragraph (b) of this section, until the quarter in which the offsets are achieved, due within 30 days after the end of the previous calendar quarter, which shall include:

(A) A description of the work accomplished;

(B) A demonstration that interim milestones were achieved;

(C) A summary of remaining work to be performed; and

(D) Proposed adjustments, if any, to the schedule.

(ii) The offset plan shall require that the designated representative submit a final report and supporting documentation with the annual report required by 40 CFR parts 72, 73, and 75, for the year during which all required offsets are achieved in full, which shall include:

(A) A description of the work performed in accordance with the offset plan;

(B) The date that the offsets were achieved;

(C) The number of tons of offsets achieved; and

(D) Documentation that the offsets were achieved.

(iii) The offset plan shall require that each report be signed by the designated representative, be submitted pursuant to this section, and contain the following certification:

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

(f) A designated representative may identify by serial number the allowances to be deducted from the compliance subaccount for purposes of compliance with the unit's sulfur dioxide emissions limitation requirements. Such identification shall be made by submission of the Compliance Deduction Form, provided in 40 CFR part 73 with the offset plan, or by electronic methods as the Administrator shall prescribe in the future.

§ 77.3 Administrator's action on offset plans.

(a) *Determination of completeness.* (1) A designated representative shall be deemed to have submitted a complete excess emissions offset plan if the plan includes all applicable information required in § 77.2(e).

(2) No offset plan shall be considered complete unless it is submitted on standard forms in appendix A of this part or through the Acid Rain Program Electronic Permitting Program System, as established by the Administrator.

(3) The Administrator shall determine whether the offset plan submitted by the source is complete within 30 days of receipt by the U.S. EPA Regional Office for the Region in which the source is located. The offset plan shall be deemed to be complete by operation of law if the Administrator fails to notify the designated representative to the contrary within 30 days of receipt.

(b) *Effect of a determination of completeness.* (1) If a designated representative has submitted a timely and complete excess emissions offset plan on a timely basis, but the Administrator has not yet made a decision on such plan, each affected unit covered by the offset plan shall be deemed to be in compliance with the prohibition in paragraph (m)(1)(i) of this section.

(2) A complete offset plan shall be binding on the designated representative, owners, and operators of the affected units at the source, and shall be enforceable against the affected source until the Administrator makes a decision on the plan.

(c) *Supplemental information.* (1) The Administrator may require, by issuing a notice for supplemental information, submission of any additional information necessary to issue an offset plan that complies with all the requirements of this part and 40 CFR parts 70 through 76 and 78.

(2)(i) The designated representative shall submit the required information within 30 days of receiving a notice for supplemental information from the Administrator unless the Administrator allows for additional time in writing as reasonable for the designated representative to collect and submit the required information, not to exceed 4 months from the date the excess emissions offset plan was first submitted to the Administrator.

(ii) A failure to submit the supplemental information within the required time period shall result in a denial of the proposed offset plan. Such denial shall be considered a decision of the Administrator for purposes of any appeal pursuant to 40 CFR Part 72, subpart H.

(d) *Proposed excess emissions offset plan.* (1) After the Administrator receives all supplemental information requested by notice, the Administrator shall issue a proposed excess emissions offset plan for the affected source.

(2) The proposed offset plan shall be based on the information submitted by the designated representative for the affected source and such other relevant information.

(3) The Administrator shall develop an administrative record for the proposed offset plan, and such record shall include:

(i) Documents submitted by the source under § 77.2(e); and

(ii) Other documents relied on by the Administrator to develop the proposed offset plan, including any records of discussions or conferences with the source or other interested persons regarding the offset plan.

(4) The Administrator shall include in the administrative record for any offset decision:

(i) The offset decision;

(ii) The administrative record for the proposed offset plan;

(iii) Copies of all written public comments submitted on the proposed offset plan;

(iv) The record of any public hearing on the proposed offset plan;

(v) Any response to public comments submitted on the proposed offset plan as required by paragraph (h) of this section, including any documents cited in the response; and

(vi) Any data, reports, or other materials submitted to, or generated by, the Administrator, during the public comment period that were considered by the Administrator in making a decision.

(5) The Administrator is required to act on a proposed excess emissions offset plan within six months of receipt.

(e) *Opportunities for public comment on proposed offset plans*—(1) *Generally.* (i) The Administrator shall give public notice of the following:

(A) Any proposed offset plan and its availability for public review and comment;

(B) Opportunity to request a public hearing on a proposed offset plan pursuant to paragraph (g) of this section; and

(C) Any scheduled hearing granted pursuant to paragraph (g) of this section.

(ii) Any public notice of a proposed offset plan given under this part may be for one or more proposed offset plans.

(2) *Timing.* Public notice under this part shall provide for:

(i) A 30-day public comment period, beginning from the date of publication of the notice of a proposed offset plan; and

(ii) An opportunity to request a public hearing on the proposed offset plan, including a scheduled date and place for the hearing if requested, to occur not earlier than 15 days after the notice is given.

(3) *Methods.* The Administrator shall give the public notice of the proposed offset plan required by this section, as follows:

(i) Actual notice shall be given to the following persons (except to the extent any such person has waived his or her right to receive such notice for any class or category of an offset plan action);

(A) The designated representative;

(B) The State or local air pollution agency and the State ratemaking authority (if any) with jurisdiction over the affected source governed by the proposed offset plan;

(C) In accordance with title V of the Act, the State or local air pollution agency for any contiguous State whose air quality may be affected by the affected source that is the subject of the proposed offset plan, or for any State located within a 50-mile radius of the affected source; and

(ii) Notice by publication in the **Federal Register** and by advertisement in the area affected by the proposed offset plan.

(4) *Contents.* All public notices issued under this part shall contain the following information:

(i) Name, and address, of the EPA office processing the offset plan for which the notice is being given;

(ii) Name, address, telephone and facsimile number of the designated representative for the affected source;

(iii) Identification of each affected unit at the source covered by the proposed offset plan as follows; name (plant, unit), address;

(iv) A brief description of the action proposed to be taken; including, for proposed offset plans:

(A) The amount of emissions that must be offset in the source's offset plan;

(B) Any alternative methods of compliance which are proposed to be approved to meet the required offset; and

(C) The period of time during which the offset is proposed to occur, if greater than one year.

(v) The address and office hours of a public location where the offset plan administrative record provided under paragraph (d)(3) of this section is available for public inspection; and a statement that all information submitted by the designated representative and not protected as confidential pursuant to section 114(c) of the Act is available for public inspections as part of the offset plan administrative record;

(vi) Name, address, telephone and facsimile number of the EPA office from whom interested persons may obtain further information;

(vii) A brief description of the public comment procedures, including:

(A) Explanation of the purpose of the public comment opportunity;

(B) The time allowed for public comments;

(C) Where public comments should be sent;

(D) Required formats and contents for public comment;

(E) The location, date, time, and procedures of any scheduled public hearing; and

(F) Any other procedures by which the public may participate.

(5) *Extensions and reopenings of the public comment period.* On the Administrator's own motion, or on the request of any person, the Administrator may, at his or her discretion, extend or reopen the public comment period where it reasonably appears that doing so will expedite the decision-making process. Notice of any such extension or reopening shall be given pursuant to this section.

(f) *Public comments*—(1) *General.* (i) Any person may submit comments on an offset plan.

(ii) Comments shall be submitted during the public comment period. Comments received after the public comment period has closed will not be considered.

(iii) Comments shall be submitted in duplicate.

(iv) The submission shall clearly indicate the proposed offset plan to which the comments apply.

(v) The submission shall clearly indicate the name of the commenter, and where appropriate, the affiliation of the commenter.

(2) *Contents.* Comments may be made on any aspect of the proposed offset plan or proposed offset plan modification.

(i) Comments will be considered when making a decision on the offset plan.

(ii) Comments will not be considered if they concern the contents of the source's permit. Comments specifically concerning the issuance of the proposed offset plan, such as requests for a public hearing on such offset plan, will be considered.

(iii) Commenters who do not wish to raise issues on the proposed offset plan, but who wish to be notified of any subsequent offset plan actions, may so indicate during this public comment period or at any other time.

(g) *Opportunity for public hearing.* (1) During the public comment period provided under paragraph (e) of this section, any person may request a public hearing. A request for a public hearing shall be made in writing and shall state the nature of the issues proposed to be raised in the hearing.

(2) The Administrator may, at his or her discretion, hold a public hearing whenever the Administrator finds that:

(i) A request for such has been made that raises significant issues affecting the terms and conditions of the offset plan and such hearing would contribute to the decision on the offset plan; or

(ii) A hearing might clarify one or more issues raised by the proposed offset plan.

(3) Public notice of the scheduling of a public hearing shall be given as specified in paragraph (e) of this section.

(4) During a public hearing under this section, any person may submit oral or written comments concerning the proposed offset plan. The Administrator may set reasonable limits on the time allowed for oral statements, shall require the submission of written summaries of each oral statement, and may extend the public comment period by so stating during the hearing.

(5) The Administrator shall assure that a record is made of the hearing, which shall be made part of the offset administrative record provided under paragraph (d)(3) of this section.

(h) *Response to comments.* (1) The Administrator shall consider comments received during the public comment period and shall respond in writing to such comments when issuing the offset decision.

(2) The response to comments shall: (i) Identify any offset plan provision which has been changed in the offset decision in response to comments made, and the reasons for the change; and

(ii) Briefly describe and respond to comments on the proposed offset plan.

(3) Any documents cited in the response to comments shall be included in the administrative record, or their location shall be cited, if readily obtainable.

(i) *Issuance and effective date of excess emissions offset plans.* (1) After the close of the public comment period, the Administrator shall:

(i) Act on the proposed excess emissions offset plan by either:

(A) Approving the excess emissions offset plan as submitted,

(B) Approving the excess emissions offset plan, in whole or in part, with any appropriate revisions;

(C) Approving the excess emissions offset plan, with expeditious and enforceable deadlines included in the plan for the conditions to be met not later than the end of the year; or

(D) Disapproving the excess emissions offset plan and either:

(1) Deducting allowances, or

(2) Issuing such order as is necessary to achieve the offsets.

(ii) Specify as part of the action an excess emissions offset period for achieving, in full, the emissions reductions required by the plan.

(iii) Give actual notice of the decision to the designated representative for the affected source, and to any persons who submitted comments during the public comment period or who are entitled to actual notice under paragraph (e)(3) of this section. The Administrator shall also give notice of the decision in the **Federal Register**.

(2) Any offset decision shall be issued and become final agency action 60 days after notice of the offset decision is published in the **Federal Register**, unless an appeal is filed pursuant to 40 CFR part 72, subpart H.

(3) The term of every offset plan shall be for the remainder of the year in which the source is required to have an offset plan, or for such larger period as is approved in the offset plan.

(j) Upon approval of the proposed offset plan by the Administrator, the offset plan shall be deemed a condition of the operating permit for the unit without further review or revision of the permit.

(k) *Deduction of allowances.* The Administrator shall deduct allowances, in accordance with the approved excess emissions offset plan, equal to the tons of excess emissions.

(1) The allowances shall be deducted in the year following the year when the excess emissions occurred, unless the Administrator approves a longer offset period.

(2) If an approvable offset plan is not timely submitted in accordance with this section, the Administrator shall deduct allowances from the annual allocations that would otherwise be made to the unit which had the excess emissions from the unit's Allowance Tracking System account in the year following the year in which excess emissions occurred.

(3) The Administrator may make a determination that allowance deductions occur over a specified period greater than 1 year provided the designated representative for the unit or units makes a showing, to the Administrator's satisfaction, that deducting the entire amount of the allowances required to offset the excess emissions during the following calendar year will interfere with electric reliability.

(l) *Binding effect of offset plan.* (1) Upon the issuance of a determination of completeness by the Administrator as provided in paragraph (a) of this section, the proposed offset plan shall be binding on the designated representatives and the owners and operators of the unit(s) governed by the plan and shall temporarily supersede any inconsistent provisions of the permit and approved compliance plan for the affected source. The proposed offset plan shall, thereafter, remain in effect until the Administrator acts on the proposed excess emissions offset plan as provided in this section.

(2) Upon issuance of a determination of completeness by the Administrator as provided in paragraph (a) of this section, the plan shall be deemed to be incorporated into the permit without further review or revision as an administrative permit amendment in accordance with 40 CFR 72.303. The Administrator's action on the plan shall be deemed a permitting decision, shall also be incorporated into the permit as an administrative amendment, and shall be subject to the appeals provisions of 40 CFR part 72, subpart H and section 307 of the Act.

(m) *Prohibitions.* It shall be a violation of this part and of the Act for the designated representative of an affected unit liable for excess emissions offsets under this part and section 411 of the Act, to fail to:

(1) Submit:

(i) A complete and approvable proposed excess emissions offset plan in a timely manner; and

(ii) Any progress reports required by this part, in a timely manner;

(2) Comply with the terms of a proposed or approved excess emissions offset plan; or

(3) Otherwise offset excess emissions as required by this part.

(n) Any failure to comply with any requirement of this part shall be a separate enforceable violation of the Act.

(o) Each day after the 60-day deadline for submitting the excess emissions offset plan, or after a reporting deadline, that the designated representative for the affected unit fails to submit a complete excess emissions offset plan shall be deemed a separately enforceable violation of the Act.

§ 77.4 Excess emissions penalties.

(a) In the event excess emissions of sulfur dioxide or nitrogen oxides occur at an affected unit during any calendar year, the designated representative of the affected unit shall submit, without demand, payment of an excess emissions penalty in accordance with this section. The designated representative, and the owners and operators of the unit with excess emissions shall be held strictly liable for the obligation to automatically pay without delay any penalty due under this part. In the case of excess emissions such payment must be received no later than 60 days after the end of any calendar year during which excess emissions occurred at an affected unit, subject to the interest obligation accruing from January 1, 1991, specified in paragraph (c) of this section.

(b)(1) The designated representative responsible for submitting the penalty shall be responsible for correctly calculating the penalty.

(2) The excess emissions penalty shall be determined using the following formula:

$$EEP = AEEPR \times Q$$

where:

EEP—is the excess emissions penalty,
AEEPR—is the adjusted excess emissions penalty rate determined in accordance with the method specified in Appendix B of this part, and
Q—is the number of tons of excess emissions.

(3) Round EEP to the nearest dollar after completing the calculation in paragraph (b)(2) of this section.

(c) In the event an excess emissions penalty due under this part is not paid in a timely manner, in accordance with paragraphs (a) and (b) of this section, the total excess emissions penalty shall be calculated to include interest, accruing from January 1 until the date on which the penalty payment is submitted, as follows:

(1) The interest rate for delayed payment (i) shall be equal to the coupon issue yield equivalent (as determined by the Secretary of Treasury) of the average accepted auction price for the last auction of 52 week U.S. Treasury bills settled for the week immediately prior to January 1 of the year the penalty is due.

(2) The total penalty, with accrued interest shall be determined using the following formula:

(i)
$$EEP_t = EEP \times (1 + i)^n$$

where:

EEP_t—is the total excess emissions penalty with accrued interest;

EEP_i—is the excess emissions penalty (as calculated in paragraph (b) of this section);
i—is the interest rate, as calculated in accordance with paragraph (c)(1) of this section; and
n—is the number of months subsequent to January 1 of the year that payment is due where the first day of each month shall increase the value of n (January 31, n=1; February 28/29, n=2; March 30, n=3).

(ii) Round EEP_i to the nearest dollar after completing the calculation in paragraph (c)(2)(i) of this section.

(d) Any excess emissions penalty shall be due and payable automatically without demand to the Administrator as follows:

(1) Payments of penalties less than $25,000 shall be made by cashier's or certified check, made payable to the U.S. Treasurer, and sent to the lock box for the EPA Regional Office for the State where the affected unit is located, at the address specified in appendix C of this part; and

(2) Payments of penalties of $25,000 or more shall be made by wire transfer to the U.S. Treasury at the Federal Reserve Bank of New York, using SF# 774 in appendix A of this part.

(3) A written confirmation of payment shall be sent to the Administrator, using SF# 774A in appendix A of this part.

(e) It shall be a violation of the Act for the designated representative of an affected unit liable for penalty payments under this part to fail to:

(1) Correctly determine the penalty amount; or

(2) Pay the penalty as required by this part.

(f) Any failure of the designated representative of an affected unit liable for excess emissions penalties under this part to comply with any requirement of this section, including any failure to pay an excess emissions penalty, shall be deemed a separately enforceable violation of the Act.

(g) Any excess emissions penalty due and payable under this paragraph shall not affect the liability of the affected unit's designated representative, owner or operator, for any additional fine, penalty, or assessment for the same violation authorized under any other section of the Act.

(h) Excess emissions in any calendar year resulting directly from an order issued in that year pursuant to Section 110(f) of the Act, shall not be subject to the penalty payment requirements of this section; provided that the designated representative of any unit subject to such order shall advise the Administrator within 30 days of issuance of the order that the order will result in such excess.

§ 77.5 Other.

The addresses for submissions, Federal authority, State authority, signatory requirements, recordkeeping, availability of information, and computation of time are provided as follows:

(a) *Addresses for submissions.* (1) All submissions required by this part that must be sent to U.S. Environmental Protection Agency headquarters shall be addressed to the Chief, Permits and Technologies Section, Acid Rain Division (ANR-445), Office of Atmospheric and Indoor Air Programs, U.S. Environmental Protection Agency, 401 M Street, SW., Washington, DC 20460.

(2) All submissions required by this part that must be sent to EPA regional offices shall be addressed to the appropriate region as follows:

Region I (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont)—Director, Air, Pesticides, and Toxics Management Division, U.S. Environmental Protection Agency, John F. Kennedy Federal Building, Boston, Massachusetts 02203.
Region II (New Jersey, New York, Puerto Rico, Virgin Islands)—Director, Air and Waste Management Division, U.S. Environmental Protection Agency, Federal Office Building, 26 Federal Plaza (Foley Square), New York, New York 10278.
Region III (Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia)—Director, Air, Radiation and Toxics Management Division, U.S. Environmental Protection Agency, 841 Chestnut Building, Philadelphia, Pennsylvania 19107.
Region IV (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee)—Director, Air, Pesticides, and Toxics Management Division, U.S. Environmental Protection Agency, 345 Courtland Street, NE., Atlanta, Georgia 30365.
Region V (Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin)—Director, Air and Radiation Division, U.S. Environmental Protection Agency, 230 South Dearborn Street, Chicago, Illinois 60604.
Region VI (Arkansas, Louisiana, New Mexico, Oklahoma, Texas)—Director, Air, Pesticides, and Toxics Division, U.S. Environmental Protection Agency, 1445 Ross Avenue, Dallas, Texas 75202.
Region VII (Iowa, Kansas, Missouri, Nebraska)—Director, Air and Toxics Division, U.S. Environmental Protection Agency, 726 Minnesota Avenue, Kansas City, Missouri 66101.
Region VIII (Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming)—Director, Air and Toxics Division, U.S. Environmental Protection Agency, 1860 Lincoln Street, Denver, Colorado 80295.
Region IX (Arizona, California, Guam, Hawaii, Nevada)—Director, Air and Toxics Division, U.S. Environmental Protection Agency, 75 Hawthorne Street, San Francisco, California 94105.
Region X (Alaska, Idaho, Oregon, Washington)—Director, Air and Toxics Division, U.S. Environmental Protection Agency, 1200 Sixth Avenue, Seattle, Washington 98101.

(3) All submissions required by this part that must be sent to a State permitting authority with an approved permit program under this part and 40 CFR part 70 shall be addressed to the applicable permitting authority as provided in 40 CFR part 70, and to the following State air pollution agencies:

State of Alabama, Air Pollution Control Division, 645 S. McDonough Street, Montgomery, Alabama 36104.
State of Arizona, Department of Health Services, 1740 West Adams Street, Phoenix, Arizona 85007.
State of Arkansas, Division of Air Pollution Control, Department of Pollution Control and Ecology, 8001 National Drive, P.O. Box 9583, Little Rock, Arkansas 72209.
State of California, Air Resources Board, 1102 Q Street, Sacramento, California 95814.
State of Colorado, Department of Health, Air Pollution Control Division, 4210 East 11th Avenue, Denver, Colorado 80220.
State of Connecticut, Department of Environmental Protection, State Office Building, Hartford, Connecticut 06115.
State of Delaware, Delaware Department of Natural Resources and Environmental Control, 89 Kings Highway, P.O. Box 1401, Dover, Delaware 19901.
District of Columbia, Department of Consumer and Regulatory Affairs, 614 H Street, NW., Washington DC 20001.
State of Florida, Bureau of Air Quality Management, Department of Environmental Regulation, Twin Towers Office Building, 2600 Blair Stone Road, Tallahassee, Florida 32301.
State of Georgia, Environmental Protection Division, Department of Natural Resources, 205 Butler Street, SE., East Tower, Atlanta, Georgia 30334.
State of Idaho, Department of Health and Welfare, Statehouse, Boise, Idaho 83701.
State of Illinois, Division of Air Pollution Control, 2200 Churchill Road, Springfield, Illinois 62706.
State of Indiana, Indiana Department of Environmental Management, 105 South Meridian Street, P.O. Box 6015, Indianapolis, Indiana 46206.
State of Iowa, Iowa Department of Water, Air, and Waste Management, Henry A. Wallace Building, 900 East Grand, Des Moines, Iowa 50319.
State of Kansas, Kansas Department of Health and Environment, Bureau of Air Quality and Radiation Control, Forbes Field, Topeka, Kansas 66620.
State of Kentucky, Division of Air Pollution Control, Department for Natural Resources and Environmental Protection, U.S. 127, Frankfort, Kentucky 40601.
State of Louisiana, Program Administrator, Air Quality Division, Louisiana Department of Environmental Quality, P.O. Box 44096, Baton Rouge, Louisiana 70804.

State of Maine, Department of Environmental Protection, State House, Augusta, Maine 04330.
State of Maryland, Air Management Administration, Maryland Department of the Environment, 2500 Broening Highway, Baltimore, Maryland 21224.
Commonwealth of Massachusetts, Massachusetts Department of Environmental Quality Engineering, Division of Air Quality Control, One Winter Street, Boston, Massachusetts 02108.
State of Michigan, Air Pollution Control Division, Michigan Department of Natural Resources, Stevens T. Mason Building, 8th floor, Lansing, Michigan 48926.
State of Minnesota, Minnesota Pollution Control Agency, Division of Air Quality, 520 Lafayette Road, St. Paul, Minnesota 55155.
State of Mississippi, Bureau of Pollution Control, Department of Natural Resources, P.O. Box 10385, Jackson, Mississippi 39209.
State of Missouri, Department of Natural Resources, P.O. Box 1368, Jefferson City, Missouri 65101.
State of Montana, Department of Health and Environmental Services, Cogswell Building, Helena, Montana 59601.
State of Nebraska, Department of Environmental Control, P.O. Box 94877, State House Station, Lincoln, Nebraska 68502.
State of Nevada, Department of Conservation and Natural Resources, Division of Environmental Protection, 201 South Fall Street, Carson City, Nevada 89710.
State of New Hampshire, New Hampshire Air Resources Agency, Health and Welfare Building, Hazen Drive, Concord, New Hampshire 03301.
State of New Jersey, Department of Environmental Protection, Division of Environmental Quality, Enforcement Element, John Fitch Plaza, CN-027, Trenton, New Jersey 08625.
State of New Mexico, Director, New Mexico Environmental Improvement Division, Health and Environmental Department, 1190 St. Francis Drive, Santa Fe, New Mexico 87503.
State of New York, Department of Environmental Conservation, Division of Air Resources, 50 Wolf Road, New York, New York 12233.
State of North Carolina, Environmental Management Commission, Department of Natural and Economic Resources, Division of Environmental Management, Attention: Air Quality Section, P.O. Box 27687, Raleigh, North Carolina 27611.
State of North Dakota, State Department of Health and Consolidated Laboratories, Division of Environmental Engineering, State Capitol, Bismarck, North Dakota 58501.
State of Ohio, Ohio Environmental Protection Agency, 1800 Watermark Drive, Box 1049, Columbus, Ohio 43266-0149.
State of Oklahoma, Oklahoma State Department of Health, Air Quality Service, P.O. Box 53551, Oklahoma City, Oklahoma 73152.
State of Oregon, Department of Environmental Quality, Yeon Building, 522 SW. Fifth, Portland, Oregon 97204.
Commonwealth of Pennsylvania, Department of Environmental Resources, 105 S. Second Street, P.O. Box 2357, Harrisburg, Pennsylvania 17120.
State of Rhode Island, Department of Environmental Management, 204 Cannon Building, Davis Street, Providence, Rhode Island 02908.
State of South Carolina, Office of Environmental Quality Control, Department of Health and Environmental Control, 2600 Bull Street, Columbia, South Carolina 29201.
State of Tennessee, Department of Public Health, Division of Air Pollution Control, 256 Capitol Hill Building, Nashville, Tennessee 37219.
State of Texas, Air Pollution Control Board, 6330 Highway 290 East, Austin, Texas 78723.
State of Utah, Department of Health, Bureau of Air Quality, 288 North 1460 West, P.O. Box 16690, Salt Lake City, Utah 84116-0690.
State of Vermont, Vermont Agency of Environmental Conservation, Air Pollution Control, State Office Building, Montpelier, Vermont 05602.
Commonwealth of Virginia, Virginia Department of Air Pollution Control, P.O. Box 10089, Ninth Street Office Building, Richmond, Virginia 23219.
State of Washington, Department of Ecology, Olympia, Washington 98504.
State of West Virginia, Air Pollution Control Commission, 1558 Washington Street East, Charleston, West Virginia 25311.
State of Wisconsin, Department of Natural Resources, P.O. Box 7921, Madison, Wisconsin 53707.

(4) For all submissions required by this part to be submitted to a State, an EPA Regional office, or EPA Headquarters, copies shall also be sent to the State, to the appropriate EPA Regional office, and to EPA Headquarters.

(b) *Federal authority.* Under authority of sections 114 and 301 of the Act, the Administrator reserves the right to:

(1) Secure information needed for the purpose of developing or implementing any standard, requirement, or prohibition under the Act, or 40 CFR parts 70 through 76 and 78 or of determining whether any person is in violation of any standard, requirement, or prohibition of the Act, this part, or 40 CFR parts 72–76 and 78;

(2) Make inspections, conduct tests, examine records, and require the designated representative, the owner, or the operator of an affected unit to submit information reasonably required for the purpose of developing or implementing any standard, requirement, or prohibition under this part, and 40 CFR parts 72–76 and 78; and

(3) Call witnesses and compel the production of documents.

(c) *State authority.* Consistent with Section 116 of the Act, the provisions of this part shall not be construed in any manner to preclude any State or political subdivision thereof from adopting and enforcing any other air quality requirement applicable to an affected source or unit: *provided* that such requirement is not less stringent than, and does not alter any requirement applicable to such unit or source prescribed under this part; and *provided*, further, that such requirement if articulated in an operating permit, is expressed in a portion of the permit separate from the portion containing the Acid Rain program requirements. Nothing in this section shall authorize a State permitting authority to modify or alter any Acid Rain program requirement except as provided in title IV and elsewhere in this part.

(d) *Signatory requirements.* (1) All Acid Rain program submissions required to be made on behalf of affected sources and affected units pursuant to this part and 40 CFR parts 70 through 76 and 78, including the submissions specified in 40 CFR 72.21, shall be made by the designated representative for the source's owners and operators by certified mail. In each submission, the designated representative shall sign and certify:

(i) That the procedure specified in the representation agreement, pursuant to 40 CFR 72.20, for obtaining the authorization of the owners and operators to take such action has been complied with; and

(ii) The following statement:

I certify under penalty of law that I have personally examined, and am familiar with, the information submitted in this document and all attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including the possibility of fine or imprisonment.

(2) The permitting authority shall only act upon submissions that have been signed, certified and filed by the duly authorized designated representative for the affected units at the source.

(e) *Recordkeeping.* Records and reports required to be maintained, issued to any person or submitted to the Administrator, a State air pollution control agency, or a permitting authority pursuant to this part, shall be kept on file at the source for a period of 5 years. This period may be extended for cause at any time prior to the end of the 5 years in writing by the Administrator or the permitting authority.

(f) *Availability of information.* The availability to the public of information provided to, or otherwise obtained by,

the Administrator under this part shall be governed by 40 CFR part 2.

(g) *Computation of time.* (1) Any time period scheduled to begin on the occurrence of a date, act, or event shall begin on the day the act or event occurs.

(2) Any time period scheduled to begin before the occurrence of a date, act, or event shall be computed so that the period ends on the day before the act or event occurs.

(3) If the final day of any time period falls on a weekend or a federal holiday, the time period shall be extended to the next business day.

(4) Whenever a party or interested person has the right, or is required, to act within a prescribed period after service of notice or other document upon him or her by mail, 3 days shall be added to the prescribed time.

Appendix A to Part 77—Excess Emissions Offset Plan Forms

1. Excess Emissions Offset Planning Form 772
2. Excess Emissions Penalty Forms 774 and 774A

BILLING CODE 6560-50-M

FORM 772

Excess Emissions Offset Planning

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

DRAFT 772
Date 10/21/91
Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Excess Emissions Offset Planning

Follow Instructions for Form 772.

I. UNIT IDENTIFICATION

A. Unit ARP ID Number

B. Short Name

C. Year of Excess Emissions

D. Excess Sulfur Dioxide Emissions *(tons)*

☐ E. Attached is a description of reasons for the excess emissions and of corrective actions taken.

II. SULFUR DIOXIDE EXCESS EMISSIONS OFFSET PLAN

☐ A. This unit proposes to offset excess emissions by using the following methods:
- ☐ 1. Substitution Plan
- ☐ 2. Reduced Utilization Plan
- ☐ 3. Deducting Allowances
- ☐ 4. Installing pollution control technology

B. Attached are:
- ☐ 1. Proposed schedule of compliance for reducing Sulfur Dioxide emissions or obtaining additional allowances.
- ☐ 2. Demonstration that compliance options will achieve reductions.
- ☐ 3. A list of provisions of the current approved compliance plan for this unit that would be revised by the proposed offset plan.

III. STANDARD PROVISIONS & PROHIBITIONS

A. Emissions Limitations
1. **Sulfur Dioxide.** The Sulfur Dioxide emissions limitation during the offset period shall be as stated in the approved offset plan.
2. **Nitrogen Oxides.** The Nitrogen Oxides emissions limitations shall be as stated in the source permit for this unit.

B. Recordkeeping Requirements
The unit shall comply with the recordkeeping requirements in the permit for this unit.

C. Reporting/Compliance Certification Requirements
1. The Designated Representative shall submit quarterly progress reports, submitted with the reports due under Section 72.401(b), commencing with the first calendar quarter following the date on which an excess emission offset plan is due until the quarter in which the offsets are achieved. Each report shall be due within 30 days after the end of the previous calendar quarter, and shall contain all information required by 40 CFR Section 77.2.
2. The Designated Representative shall submit a final report with the annual report required by 40 CFR Parts 72, 73, and 75 for the year during which all required offsets are achieved in full, and shall contain all information required by 40 CFR Section 77.2.

D. Prohibitions
1. It shall be a violation for an allowance to be transferred during the offset period from the Allowance Tracking System account for the affected unit responsible for the offsets that might cause further excess emissions at the unit.
2. It shall be a violation for the Designated Representative to fail to submit any plans or reports required under 40 CFR Section 77.2 in a timely manner, to fail to comply with the terms of an approved plan, or to otherwise fail to offset emissions as required by 40 CFR Part 77.2.

IV. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*

B. Signature

C. Date Signed

FOR EPA USE ONLY

1. Date Received: ____________
2. Date of Initial Review: ____________ By: ____________
   a. ☐ Complete ☐ Incomplete
   b. ☐ Approved ☐ Disapproved Explain: ____________
3. Date of Final Approval: ____________ By: ____________
4. Date Notice Sent: ____________ By: ____________

Comments:

772/pg.1

BILLING CODE 6560-50-C

Phase I Acid Rain Permit Program—Instructions For Form #772

Form #772—Excess Emissions Offset Planning

Introduction

Clean Air Act Section 411(b) and the regulations implementing that section at 40 CFR §§ 77.2 and 77.3 require that any affected unit that emits sulfur dioxide in excess of the unit's emissions limitation or of the allowances held for the unit in a given year must offset the excess emissions by an equal tonnage amount in the following year. The Designated Representative is required to submit to the Permitting Authority a plan to achieve the required offsets within 60 days after the end of the year in which the excess emissions occurred.

Instructions

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. Unit Identification

A and B. Enter the unit Acid Rain Program Identification Number and the short name for the unit given in the Acid Rain permit application at Part I, Sections A and B.

C. Indicate the year in which excess emissions occurred for which you are submitting this proposed plan.

D. Enter the number of excess tons of emissions being reported on this form.

E. Indicate that you have attached a description of why the excess emissions occurred, (*e.g.*, emissions reductions equipment failed to perform as expected, utilization was increased, etc.), and of the corrective action taken during the year of the excess emissions to prevent or minimize the excess.

II. Sulfur Dioxide Excess Emissions Offset Plan

A. Proposal to Offset Emissions: For excess emissions that occur during Phase I, the unit has the option to offset those emissions by the following methods:

1. The unit can shift the emissions reduction requirement that the offsets represent to another affected unit, including a substitute unit under a substitution plan filed on SF# [7241].

2. The unit can offset the emissions by reducing utilization, in which case the unit must file a reduced utilization plan on SF# [7243].

(The components of and requirements for both of these plans are listed in the instructions package for the Acid Rain Program application forms, available from your EPA Regional Office or EPA Headquarters.)

3. The unit can offset emissions by deducting from the unit's Allowance Tracking System compliance subaccount for the following year the number of allowances equal to the tons of excess emissions.

4. The unit can offset emissions by installing control equipment that reduces emissions at the unit to a level that will meet the emissions limitations required under the permit, and will compensate for the additional emissions reductions required by the offset.

Note: If the excess emissions will be offset using only the standard offset method (*i.e.*, deducting the entire amount of allowances equal to the tonnage of excess emissions from the unit's Allowance Tracking System Compliance subaccount for the following calendar year), *mark only A 3 above.*

B. You must attach the following to make the offset plan complete:

1. A schedule of compliance for reducing SO_2 emissions or obtaining additional allowances. This schedule must include the number of allowances required to be deducted from the unit's allowance tracking system account and the appropriate increments of progress for the following: reducing sulfur dioxide emissions; deducting offset allowances (include serial number of allowance) from the unit or units responsible under the plan for achieving the offsets; obtaining additional allowances; and, taking corrective action.

2. A demonstration that the reductions achieved by relying on one or more Acid Rain compliance options of 40 CFR Part 72, Subpart D is equal to the reductions required by a standard excess emissions offset plan, in accordance with paragraph § 77.2(e)(5)(iii).

3. A list and description of the provisions of the current compliance plan that would be revised by the proposed offset plan. A proposed offset plan will be subject to public comment. An approved offset plan will be an administrative amendment of the permit and will not be subject to further review.

III. Standard Provisions and Prohibitions

Part III does not require that you supply any information. Note, however, that during the offset period, the Designated Representative is prohibited from submitting an allowance transfer from the Allowance Tracking System account for the affected unit responsible for the offsets if that transfer might cause further excess emissions at the unit.

IV. Certification

The proposed Designated Representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See Part III, Section A of the Forms Instruction Package for more information about the legal effect of certification.

BILLING CODE 6560-50-M

FORMS 774 and 774A

Excess Emissions Penalty

Form 774

Excess Emissions Penalty

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

Form 774A

Funds Transfer Deposit

Paperwork Burden Estimate:

Public reporting burden for this collection of information is estimated to average _____ hours per response, including the time for completing the form and copying, assembling and sending the form. Send comments regarding this collection of information, including suggestions for reducing the burden, to Chief, Information Policy Branch, PM-223, U. S. Environmental Protection Agency, 401 M Street, S.W., Washington, D.C. 20460; and to Paperwork Reduction Project (OMB # 20xx-xxxx), Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503.

DRAFT 774
Date 10/21/91
Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Excess Emissions Penalty

Follow Instructions for Form 774.

I. UNIT IDENTIFICATION

A. Unit ARP ID Number	B. Short Name	C. Year

II. EXCESS EMISSIONS PENALTY CALCULATIONS

A. Total Excess Emissions:

☐ 1. This unit reported excess tons of Sulfur Dioxide totalling

☐ 2. This unit reported excess tons of Nitrogen Oxides totalling

3. Total excess tons →

B. Penalty Calculation:

1. Total excess tons *(enter A.3.)*

2. Excess emissions penalty rate (EEPAR)

3. TOTAL PENALTY DUE *($)* →

C. Late Payment Calculation:

1. Excess emissions penalty

2. Late payment penalty rate

3. Late payment penalty →

III. CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this and accompanying documents. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the information is on knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false or incomplete information, including possibility of fine or imprisonment.

A. Name of Designated Representative *(please print)*

B. Signature

C. Date Signed

FOR EPA USE ONLY

1. Date Original Received: ____________
2. Date of Initial Review: ____________ By: ____________

☐ Approved ☐ Disapproved
Explain: ____________

LOCKBOX COPY

1. Date Received at EPA Regional Office: ____________ By: ____________
2. Date Received at EPA Accounting Office: ____________ By: ____________

DRAFT 774A
Date 10/21/91
Please print or type in the unshaded areas only.

Source ARP ID Number

Form Approved
OMB No. XXXX-XXXX
Approval Expires X-XX-XX

FORM ARP

U.S. ENVIRONMENTAL PROTECTION AGENCY

Funds Transfer Deposit

Reserved for instructions

ID	TYPE
XXXXXXXX	10

AMOUNT
$

SENDER

RECEIVER
TREAS NYC/ EPA

THIRD PARTY INFORMATION

BILLING CODE 6560-50-C

Phase I Acid Rain Permit Program—Instructions for Forms #774 and 774A

Forms #774 and 774A—Excess Emissions Penalty Form

Introduction

Clean Air Act § 411 and the regulations implementing that section at 40 CFR § 77.4 provide that the designated representative for a unit that emits NO_x in excess of the unit's emissions limitation or emits SO_2 in excess of the allowances held for the unit shall be liable for the payment of an excess emissions penalty. The Designated Representative is responsible for calculating the penalty, and must submit the penalty without demand within sixty (60) days after the end of the calendar year in which the excess emissions occurred.

Instructions for Form #774—Excess Emissions Penalty Form

Top Center of Each Page: Enter the Acid Rain Program Identification Number (the AIRS number) for the source.

I. Identification

A. Enter the Acid Rain Program Identification Number and short name for the unit given in the Acid Rain permit application at Part I, Sections A and B (SF# 7231A).

B. Indicate the year for which the penalty is being submitted, *i.e.*, the year in which the excess emissions occurred.

II. Excess Emissions Penalty Calculation

A. List the tons of excess emissions for the reporting year. This information will be in the Electronic Emissions Tracking system. For the figures entered in 1 and 2, *any* fraction of a ton is rounded up to equal a ton.

1. Check this box if the unit had excess SO_2 emissions and enter amount.

2. Check this box if the unit had excess NO_x emissions and enter amount.

B. Penalty Calculation: 1. Enter excess tons figure from A 3.

2. Enter the Adjusted Excess Emissions Penalty Rate (AEEPR) figure. To calculate this rate, see 40 CFR Part 77, Appendix B.

3. Enter product, which is the penalty due.

C. Late Payment Penalty: If you submit this payment beyond the allowance transfer deadline that occurs after the end of the calendar year for which you are reporting excess emissions, you will be responsible for submitting an additional penalty, calculated as follows:

1. Enter Excess Emissions Penalty figure from B 3.

2. Enter the sum of one plus the interest rate raised to the n^{th} power $[1+(i)]^n$, where "i" is the interest rate and "n" is the number of months that have elapsed since the due date. See 40 CFR § 77.4(c)(2) to calculate this factor.

3. Enter the product of C 1 multiplied by C 2, rounded to the nearest dollar.

The original of this form must be submitted to the Permitting Authority. Payments for penalties less than $25,000 should be made by cashier's or certified check payable to "Treasurer, United States of America, Acid Deposition Excess Emission Penalty." A copy of the form and these payments should be sent to the lockbox for the EPA Regional Office for the State where the affected unit is located, at the address specified in Figure 2 at Section III of the Forms Instruction Package.

Payments for penalties of $25,000 or more shall be made by wire transfer to the U.S. Treasury at the Federal Reserve Bank of New York, using SF#[774A].

III. Certification

The proposed Designated Representative must sign this form and thereby certify to the truth, accuracy and completeness of the information provided in the form. See Part III, Section A of the Forms Instructions Package for more information about the legal effect of certification.

Instructions for Form #774A—Funds Transfer Deposit

Note: the nine digit identifier under "ID", the "Type" number, and the eight digit receiver code will be preprinted by EPA on final form.

To submit penalty payments of $25,000 or greater, the designated representative must use a funds transfer deposit form. The designated representative must fill in the amount of the penalty in the appropriate space, and must indicate in the third party information space (in 200 characters or less)

- The name of the payer; and
- The purpose of the payment.

The payer must present the form to the bank and request a funds transfer. If the payer's bank is not a member of the Federal Reserve system, the information on this form must be provided by the payer's bank to its corresponding FRS member bank before the transfer can be made. The bank should transmit the funds over the Federal Reserve Communication System (FEDWIRE) to the Federal Reserve Bank in New York.

Appendix B to Part 77—Method for Adjusting Excess Emissions Penalty Rate

1.0 Applicability

1.1 This Appendix establishes the method for adjusting the Acid Rain excess emissions penalty rate annually for inflation in accordance with Section 411(c) of the Act.

2.0 Principle

2.1 Each year the statutory base excess emissions penalty rate ($2000 per ton) shall be adjusted for inflation using the Consumer Price Index (CPI).

2.2 By October 15 of each year, the Administrator will publish the CPI=adjusted excess emissions penalty rate (AEEPR) for that year using the formula specified in 3.0, below.

2.3 The CPI for 1990 was 124.6.

3.0 Adjusted Excess Emissions Penalty Rate (AEEPR) Calculation

3.1 The AEEPR can be determined using the following formula:

$AEEPR = EEPAR \times 2000$

3.2 The EEPAR can be determined using the following formula:

$EEPAR = 1 + \{ [CPI(year) - CPI(1990)] \div CPI (1990)\}$

3.3 The EEPAR is then rounded to the nearest thousandths place.

3.4 Multiply EEPAR by the $2000 statutory base penalty to derive AEEPR.

4.0 Example

4.1 Calculate the adjusted excess emissions penalty rate for excess emissions that occur in 1997, assuming that the CPI on the date of enactment was 124.6 and the CPI for 1997 is 143.5.

4.2(a) Subtract 124.6 (CPI 1990) from 143.5 (CPI 1997).

$143.5 - 124.6 = 18.9$

(b) Divide this difference by 124.6 (CPI 1990).

$18.9 \div 124.6 = 0.15168539326 \ldots$

(c) Add one to this quotient.

$1 + 0.1516853926 \ldots = 1.15168539326 \ldots$

(d) Round this sum to the nearest thousandths place.

$1.15168539326 \ldots \approx 1.152$

(e) 1997 EEPAR = 1.152

(f) Multiply 2000 by the EEPAR.

$AEEPR = \$2000 \times 1.152 = \$2304$

4.3 This example is an estimate. The actual excess emissions penalty adjusted rate for 1997 is not yet known and may differ.

Appendix C to Part 77—Lock Box Addresses [Reserved]

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Tuesday
December 3, 1991

Part III

Department of Agriculture

Rural Electrification Administration

7 CFR Part 1773
Policy on Audits of REA Borrowers; Final Rule

Agency Information Collection under Office of Management and Budget (OMB) Review for Policy on Audits of REA Borrowers; Notice

DEPARTMENT OF AGRICULTURE

Rural Electrification Administration

7 CFR Part 1773

RIN 0572-AA36

Policy on Audits of REA Borrowers

AGENCY: Rural Electrification Administration, USDA.

ACTION: Final rule.

SUMMARY: The Rural Electrification Administration (REA) is revising existing policy to require an audit in accordance with generally accepted government auditing standards, to include the latest auditing standards promulgated by the American Institute of Certified Public Accountants (AICPA) and the Comptroller General of the United States, to strengthen REA's policies concerning resolution of audit recommendations, to address the Department's regulations on debarment and suspension, and to require certified public accountants (CPA) to notify the Office of Inspector General (OIG) of the United States Department of Agriculture (USDA) directly of irregularities.

EFFECTIVE DATE: December 31, 1991.

FOR FURTHER INFORMATION CONTACT: Mr. William E. Davis, Director, Borrower Accounting Division, Rural Electrification Administration, room 2221, South Building, U.S. Department of Agriculture, Washington, DC 20250, telephone number (202) 382-9450.

SUPPLEMENTARY INFORMATION:

Executive Order 12291

This final rule has been issued in conformance with Executive Order 12291 and Departmental Regulation 1512-1. This action has been classified as "nonmajor" because it does not meet the criteria for a major regulation as established by the Order.

Regulatory Flexibility Act Certification

Gary C. Byrne, Administrator, REA, has determined that this final rule will not have a significant economic impact on a substantial number of small entities as defined in the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) because most borrowers of REA loans do not meet the requirements for small entities. Further, the regulations are applied equally to all borrowers.

Information Collection and Recordkeeping Requirements

In compliance with the Office of Management and Budget (OMB) regulations (5 CFR part 1320) which implements the Paperwork Reduction Act of 1980 (Pub. L. 96-511) and section 3504 of that Act, the new information collection and recordkeeping requirements contained in this final rule have been submitted to OMB for approval. Comments concerning these requirements should be directed to the Office of Information and Regulatory Affairs of OMB, Attention: Desk Officer for USDA, room 3201, NEOB, Washington, DC 20503.

National Environmental Policy Act Certification

Gary C. Byrne, Administrator, REA, has determined that this final rule will not significantly affect the quality of the human environment as defined by the National Environmental Policy Act of 1969 (42 U.S.C. 4321 *et seq.*). Therefore, this action does not require an environmental impact statement or assessment.

Catalog of Federal Domestic Assistance

The program described by this final rule is listed in the Catalog of Federal Domestic Assistance Programs under numbers 10.850—Rural Electrification Loans and Loan Guarantees; 10.851—Rural Telephone Loans and Loan Guarantees; 10.852—Rural Telephone Bank Loans; and 10.853—Rural Economic Development Loans and Grants. This catalog is available on a subscription basis from the Superintendent of Documents, the United States Government Printing Office, Washington, DC 20402.

Executive Order 12372

This final rule is excluded from the scope of Executive Order 12372, Intergovernmental Consultation. A Notice of Final rule entitled Department Programs and Activities Excluded from Executive Order 12372 (50 FR 47034) exempts REA and Rural Telephone Bank (RTB) loans and loan guarantees, and RTB bank loans, to governmental and nongovernmental entities from coverage under this Order.

Background

The standard REA security instrument contains a provision requiring REA borrowers to prepare and furnish to REA, at least once during each 12-month period, a full and complete report of its financial condition, operations, and cash flows, in form and substance satisfactory to REA, audited and certified by an independent certified public accountant (CPA), satisfactory to REA, and accompanied by a report of such audit, in form and substance satisfactory to REA.

The security instrument covenant is directly related to the expenditure of moneys loaned and the security for loans and is, therefore, authorized by the Rural Electrification Act of 1936. This final rule implements the security instrument provision by, among other things, setting forth the requirements for an audit report which will be in form and substance satisfactory to REA.

One of the reasons REA is revising 7 CFR part 1773, Policy on Audits of REA Borrowers, is to comply with Departmental Regulation 1700-1, Basic OIG Investigation/Audit Organization and Procedures. Departmental Regulation 1700-1 requires USDA Agencies that fund individuals or entities and require audits of those entities or individuals by nonfederal auditors, to require those audits to be performed in accordance with generally accepted government auditing standards (GAGAS). Current REA policy requires audits to be performed in accordance with generally accepted auditing standards (GAAS). As a result, the borrower will be required to furnish REA a report on compliance and a report on internal controls. These reports must be prepared by a CPA and submitted with the financial statements, auditor's report, and management letter currently required by REA.

Additionally, this final rule adopts audit standards issued by the AICPA, USDA guidelines for debarment and suspension, and a requirement set forth in Departmental Regulation 1700-1 that CPAs report all accounting irregularities directly to USDA's OIG. Also, as required by Departmental Regulation 1700-1, REA is revising its audit policy to provide access to OIG and the General Accounting Office (GAO) to all audit-related documents, including audit reports, workpapers, and management letters prepared by nonfederal auditors.

Based upon the comments received on the proposed rule, several formatting changes have been made in this final rule. In the proposed rule, definitions of terms were interspersed throughout the regulation; however, in this final rule, we have created a separate definitions section. In the proposed rule, the provisions setting forth the borrower's responsibility for selecting a CPA to perform the annual audit and notifying REA of the selection were included in §§ 1773.2(d), 1773.3(a)(1), 1773.15 and 1773.17. These sections have been combined in this final rule under § 1773.3. These changes do not effect any policy changes from the proposed rule but were intended only to make this final rule a more workable document. As a result of these changes, § 1773.16, Audit Agreement, was renumbered to § 1773.6 and moved to subpart A, thereby eliminating the need for subpart

C. REA Requirements for the Selection of a CPA and for Obtaining REA Approval of the Selection. All subsequent subparts have been retitled accordingly.

Section 1773.18, Dismissal of CPA, was deleted from this final rule because REA believed this information was not critical to the implementation of its security instrument provisions.

Comments

A proposed rule published April 5, 1991, at 56 FR 14154, invited interested parties to submit comments on or before June 4, 1991. Comments were received from electric and telephone borrowers, CPAs, attorneys, statewide organizations, professional associations, and industry representatives. The following paragraphs address various topics that are discussed by the commenters.

Authority to Issue Rule

Comment. One commenter argues that REA is a lender and not a regulator and, therefore, does not have the authority to issue rules establishing audit requirements for its borrowers.

Response. This comment goes to REA's legal authority to issue this final rule. Section 4 of the Rural Electrification Act of 1936, as amended (7 U.S.C. § 904), empowers REA to make loans:

> On such terms and conditions relating to the expenditure of the moneys loaned and the security therefor as the (REA) Administrator shall determine * * *.

REA has for some time included a covenant in its standard form of security instrument requiring borrowers to prepare and furnish to REA, at least once during each 12-month period, a full and complete report of its financial condition, operations, and cash flows, in form and substance satisfactory to REA, audited and certified by an independent CPA, satisfactory to REA, and accompanied by a report of such audit, in form and substance satisfactory to REA.

The security instrument covenant is directly related to the expenditure of moneys loaned and the security for loans and is, therefore, authorized by the Rural Electrification Act of 1936. This final rule implements the security instrument provision by, among other things, setting forth the requirements for an audit report which will be in form and substance satisfactory to REA. As provided in this final rule, a satisfactory audit report must state that an audit has been performed in accordance with GAGAS and this final rule. As a result, a satisfactory audit report cannot be issued unless and until an audit has been performed in accordance with GAGAS and this final rule. This final rule also implements the security instrument covenant by setting forth REA's policy on the selection and retention of independent CPAs to perform audits of REA borrowers, and the audit procedures and documentation standards for work done in connection with audit reports prepared for REA borrowers. As a result, this final rule is authorized by the Rural Electrification Act of 1936.

OMB Circular A–133

Comment. One commenter questions whether OMB Circular A–133, Audits of Institutions of Higher Education and Other Nonprofit Organizations, applies to the REA cooperative borrowers. If not applicable, this commenter states that the rule should be clarified.

Response. REA believes that Circular A–133 does not and should not apply to REA cooperative borrowers because REA cooperatives are not operated in the public interest or to serve a public purpose as required by the circular's definition. In addition, the circular's definition of nonprofit institution is almost identical to the definition used by Congress which was originally based upon the 501(c)(3) exemption of the Internal Revenue Code of 1954 (26 U.S.C.). REA cooperatives are not organized or operated exclusively for any of the purposes provided in 501(c)(3). Rather, REA cooperatives qualify for tax exempt status under 501(c)(12). REA discussed this position with OMB who granted REA cooperatives an exemption from the requirements of Circular A–133. This final rule is clarified.

GAGAS Audit Requirement

Comment. Many commenters believe that this rule should simply require an audit to be performed in accordance with GAGAS without quoting, paraphrasing, or interpreting the GAGAS requirements. Some commenters point out that future revisions to GAGAS may require revisions to part 1773 and it would be unclear in the interim which audit requirements would take precedence. Other commenters voice concern over the manner in which GAGAS requirements and REA requirements were intermingled throughout the proposed rule, thereby making it unclear as to what was an REA interpretation of GAGAS and what was a specific REA audit requirement.

Response. REA understands the confusion arising from the format of the proposed rule. REA has distinguished between the requirement for a GAGAS audit and the additional audit procedures required by REA. The appropriate subparts and individual sections in this final rule have been reorganized and retitled to distinguish between the requirements. Similarly, the introduction to subpart F has been revised to clearly state that the audit procedures contained therein must be performed on an annual basis, regardless of whether the CPA concludes that the procedures fall outside the scope of a GAGAS audit. This final rule also adopts the recommendation not to repeat or paraphrase the GAGAS requirements.

Comment. Several commenters believe that the additional cost of performing a GAGAS audit would place a significant financial burden on REA borrowers. One commenter argues that the added responsibilities of a GAGAS audit would drive the sole practitioner and small CPA firm from the marketplace, thereby lessening competition and ultimately raising audit fees.

Response. The AICPA's comment states that:

> * * * there is no difference in the nature, timing, and extent of the audit work required to be performed under GAGAS and those (audits) performed under GAAS.

The only additional requirement imposed by a GAGAS audit is the issuance of a report on compliance, and a report on internal controls. REA does not believe, therefore, that requiring a GAGAS audit instead of a GAAS audit will impose significant cost increases on REA borrowers or, ultimately, on the final consumers.

Comment. The proposed rule states that the CPA shall adhere to GAGAS unless directed otherwise by REA, in writing. Several commenters question REA's legal authority to direct the CPA since REA has no contractual relationship with the CPA.

Response. REA's contractual relationship is with the borrower and as such, REA can impose certain requirements on the borrower through this regulation. One of the requirements adopted by this final rule is for the borrower to enter into an audit agreement with the CPA. This final rule further stipulates that the audit agreement must include a provision that the CPA will perform the audit in accordance with this regulation.

Audit Procedures

Comment. Subpart E, Audit Procedures and Documentation, of the proposed rule includes specific audit

procedures and documentation requirements. Similarly, § 1773.41, Advance of Funds, of the proposed rule includes audit procedures to be performed to test compliance with 7 CFR part 1721, Post-Loan Policies and Procedures for Insured Electric Loans, subpart A, Advance of Funds. Many commenters state that the requirements proposed in subpart E and § 1773.41 far exceed the requirements of a GAGAS audit. Others believe that the auditor should be allowed to use professional judgment in determining the extent of the audit procedures performed.

Response. REA's best interests are served if certain minimum audit requirements are enforced to ensure uniformity in the quality and extent of the audits submitted to REA. As such, the general audit requirements set forth in subpart E of this final rule contain audit procedures and documentation requirements that address plant, long-term debt, or areas unique to cooperative or utility operations. REA considers these areas to be the backbone of the financial statements for an REA borrower and are, therefore, considered critical to the auditing and reporting process. It should also be noted that these audit procedures were required in REA's previous audit regulations. Based on the comments provided, however, this final rule does not contain many of the detailed audit procedures set forth in the proposed rule. For example, the specific requirements to comply with Part 1721 have been eliminated. With respect to the audit procedures set forth in the proposed rule that have been deleted, the auditor must exercise professional judgment to determine the nature, timing, and extent of the tests to be performed.

Materiality

Comment. The proposed rule would establish a zero materiality level for testing related party transactions and irregularities, and a $1,000 materiality threshold for reporting disallowances found in tests for compliance with part 1721. A majority of the commenters voice concern that by imposing such materiality levels, the auditor would be required to test each and every transaction during the audit year. Several commenters suggest that REA adopt the requirements of Statement of Financial Accounting Standards (SFAS) No. 57, Related Party Disclosures, while others recommend adopting the provisions of Statement of Auditing Standards (SAS) No. 53, the Auditor's Responsibility to Detect and Report Errors and Irregularities.

Response. REA recognizes that it is impossible for an auditor to test every transaction occurring during the audit period. Therefore, the materiality standard for related party transactions is adopted by this final rule. The auditor is required, however, to comment on any material related party transactions not disclosed in the financial statements.

SAS No. 53 sets forth the auditor's responsibilities to detect and report material errors and irregularities. For the reasons stated in the discussion of related party transactions, the materiality standard for testing for irregularities is adopted by this final rule. However, irregularities deemed immaterial by the auditor may, in fact, be material to REA and for that reason, this final rule contains a provision that requires the auditor to report all irregularities detected regardless of materiality.

Comment. One commenter states that materiality should be defined as a percentage of the borrower's gross revenue or other standard measure.

Response. When a CPA determines whether an item is material, many different aspects of the financial statements must be taken into consideration. It is not feasible, therefore, to define a standard measure for materiality. Consequently, this final rule does not adopt a standard definition of materiality.

Irregularities and Illegal Acts

Comment. The proposed rule states that the auditor shall report all instances or indications of irregularities and illegal acts, regardless of materiality. Several commenters argue that only actual irregularities acts should be reported. These commenters note that if an indication of an irregularity exists, GAGAS requires the auditor to expand testing to determine the actual existence of the irregularity. If the indication proves invalid, no reporting should be required. If, however, the additional tests disclose an actual irregularity, reporting would be required.

Response. This final rule adopts the provision that only actual irregularities be reported to REA. However, because the determination of an illegal act is normally beyond the auditor's professional competence, the auditor must report all indications or instances of illegal acts.

Comment. Two commenters recommend that this final rule adopt the definition of irregularity provided in SAS No. 53.

Response. This final rule adopts the definition of irregularity as provided in SAS No. 53.

Comment. One non-accountant commenter states that the definition of irregularity is so vague and indefinite that it is impossible to determine what a CPA's obligation is for testing and reporting.

Response. The definition of irregularity in the proposed and final rules is the one promulgated by the AICPA in SAS No. 53. It is, therefore, universally applied by CPAs.

Comment. One commenter states that a CPA has a confidential relationship with his/her clients and is not a public investigation agency.

Response. Rule 301, Confidential Client Information, of the AICPA's Code of Professional Conduct states, in part:

> A member in public practice shall not disclose any confidential client information without the specific consent of the client.

This final rule requires the audit agreement between a borrower and CPA to state that the CPA must follow the requirements for reporting irregularities and illegal acts outlined in § 1773.9 of this part. The CPA should consider this provision before entering into an audit agreement with a borrower. By executing an audit agreement containing this provision, the CPA and borrower mutually agree that the CPA must report irregularities and illegal acts to REA and OIG. As a result, the CPA, with the consent of the borrower as required by Rule 301, will have knowingly and voluntarily waived any basis for claiming that its knowledge of irregularities and illegal acts should be kept confidential. This final rule adopts the irregularity and illegal act reporting requirements as proposed.

Comment. One commenter suggests that irregularities be reported by the board of directors, not the CPA.

Response. REA believes that it is essential to have an independent, third party notification of irregularities. This final rule adopts this requirement.

Plan of Corrective Action

Comment. Several commenters argue that a cooperative's board of directors has the responsibility to determine if and what corrective action is appropriate, and that involvement by REA is unnecessary.

Response. REA has a legitimate and substantial interest in assuring that a borrower considers all audit findings and recommendations, determines which should be implemented, and establishes a plan for corrective action. For this reason, this final rule adopts the provision set forth in the proposed rule that requires a plan of corrective action to be submitted to REA. It should be

noted, however, that REA is not requiring the implementation of all recommendations. Nonetheless, a borrower should justify, in writing, the reasons for not implementing audit recommendations and submit this justification to REA.

Physical Inspection of Plant

Comment. A majority of the commenters state that auditors are not qualified to verify the physical existence of plant facilities. Others argue that the consulting engineer inspects work orders and the resulting plant, and any duplication by the auditor would only add unnecessary time and expense to the audit process.

Response. This final rule does not adopt a requirement for the CPA to verify the physical existence of plant facilities.

Audit Agreement

Comment. A majority of the commenters take exception to the proposal that requires the audit agreement to include a statement that the audit is being performed as a requirement of the REA security instrument, and that any violation of REA audit or documentation requirements will place the REA borrower in default of the security instrument. One commenter argues that REA cannot demand a contractual admission against interest by either a borrower or the borrower's CPA by requiring either party to agree that a violation of the audit requirements set forth in part 1773 places the borrower in default.

Response. The standard REA security instrument contains a provision requiring borrowers to prepare and furnish, at least once during each 12-month period, a full and complete report of its financial condition, operations, and cash flows, in form and substance satisfactory to REA, audited and certified by an independent CPA, satisfactory to REA, and accompanied by a report of such audit, in form and substance satisfactory to REA. This final rule implements this security instrument provision and, among other things, sets forth the requirements for an audit report which will be in form and substance satisfactory to REA. An auditor's report, report on compliance, report on internal controls, and management letter, as outlined in part 1773, will satisfy the audit report requirement of the REA security instrument.

As provided in this final rule, the auditor's report must state that the audit was conducted in accordance with GAGAS and the management letter must state that the audit was conducted in accordance with part 1773. As a result, a satisfactory audit report cannot be issued unless and until an audit has been performed in accordance with GAGAS and part 1773. Accordingly, REA interprets the security instrument such that its borrowers will be in default if an audit is not performed in compliance with GAGAS and part 1773. This final rule reflects this interpretation, as well as a requirement that the audit agreement between the borrower and CPA include an acknowledgment by the borrower and CPA that REA regulations provide, at § 1773.1(c)(4), that borrowers will be in default if an audit is not performed in compliance with GAGAS and part 1773. As a result, the audit agreement is not a contractual admission against interest, but merely an acknowledgment of the provisions of § 1773.1(c)(4). If an annual auditor's report, report on compliance, report on internal controls, or management letter fails to meet the requirements of this part, it will be returned to the borrower with a written explanation of noncompliance. The borrower will have 60 days from the date of the letter detailing the noncompliance to submit corrected reports to REA. If corrected reports are not received within 60 days of the date of the letter detailing the noncompliance, REA may notify the borrower that a default has occurred under its security instrument or take other appropriate action. The default notice will set forth the period of time during which the default will be remedied.

Comment. Many commenters argue that the auditor is, by definition, independent of the borrower and REA's audit agreement requirement would place the borrower in the position of overseeing the audit at a level inconsistent with an independent audit.

Response. The CPA must be independent of the borrower in order to perform the annual audit of the borrower's financial statements. The borrower must allow the CPA to act independently and will, in no way, hinder the CPA from the independent performance of the audit.

Comment. Some commenters believe that the proposal is inappropriate because borrowers have only limited control over the procedures followed by the auditor.

Response. REA has a legitimate and substantial interest in assuring that the information contained in a borrower's financial statements presents fairly the borrower's financial position, results of operations, and cash flows for the period. For this reason, REA prescribes certain minimum audit requirements. REA's contractual relationship is with its borrower, not the CPA. Therefore, any remedies for failure to comply with REA's audit requirements must be exercised against the borrower. As a result, REA is adopting the terms of the audit agreement as discussed in this final rule.

Comment. Some commenters argue that failure to comply with REA's audit requirements constitutes a default under the security instrument only upon the provision of written notice as required in the security instrument.

Response. If an auditor's report, report on compliance, report on internal controls, or management letter fails to meet the requirements of this final rule, it will be returned to the borrower with a written explanation of noncompliance. The borrower will have 60 days from the date of the letter detailing the noncompliance to submit corrected reports to REA. If corrected reports are not received within 60 days of the date of the letter detailing the noncompliance, REA may notify the borrower that a default has occurred under its security instrument or take other appropriate action. The default notice will set forth the period of time during which the default will be remedied. It should be noted, however, that default occurs with the act of noncompliance. For the reasons set forth above, REA is adopting the requirement that the audit agreement acknowledge that REA regulations provide, at § 1773.1(c)(4), that a borrower is in default if the audit is not performed in compliance with GAGAS and part 1773.

Comment. One commenter argues that only a material breach of the security instrument, which the borrower has knowledge or reasonably should have knowledge, should be considered a default.

Response. Before REA may exercise certain remedies under the security instrument, the borrower must be given written notice and 30 days to cure the default. This notice provides knowledge to the borrower. Further, if the noncompliance is, in fact, immaterial, 30 days should be sufficient time to cure the default. However, if the default cannot be cured within 30 days, REA believes that it is reasonable for it to be in a position to determine whether to exercise any remedies which may be available.

Compliance Testing for All Levels of Government

Comment. Several commenters state that while the proposed rule quotes the requirements for a GAGAS audit with

respect to considering the audit requirements of all levels of government, the primary users of the financial statements are REA and other lenders. These commenters argue that the audit should be tailored to meet the needs of those users. Other commenters state that by reiterating this GAGAS requirement, the REA requirement may be interpreted to be much broader than it should be. Others argue that it is not feasible for an audit to fulfill the legal and regulatory needs of all levels of government.

Response. The proposed rule clearly states the GAGAS requirement that all levels of government must be addressed in planning an audit. GAGAS goes on to state that in many instances, an audit of an organization, program, activity, or function may be required by Federal, state, and local laws, regulations, and ordinances. When this situation exists, the auditor should ascertain what governments are to be served by the audit, and, to the maximum extent practicable, plan the audit so that it will help fulfill the legal and regulatory needs of identified potential users. GAGAS does, therefore, acknowledge that it is not necessary to address all levels of government, but only those that will fulfill the legal and regulatory needs of the government agencies using the auditor's report. As previously discussed, however, any repetition or paraphrasing of the GAGAS requirements is not contained in this final rule. This proposed requirement is not expressly stated in this final rule; however, GAGAS requirements must be applied.

Availability of Audited-Related Documents to OIG and GAO

Comment. Several commenters note that the laws of many states provide that workpapers are the personal property of the auditor while others argue that they are proprietary to the auditor. As such, these commenters believe that auditors may be reluctant to make certain audit-related documents available, such as planning documentation, risk assessment material, and audit programs. One commenter argues that borrowers may be reluctant to share certain information with their auditors if they know that information can be copied and obtained by others.

Response. This final rule requires the audit agreement between the borrower and CPA to state that all audit-related documents must be made available by the CPA to REA, OIG, and GAO upon request. While audit-related documents may be the personal property of, or proprietary to the CPA, the CPA is not prohibited by law from entering into an audit agreement containing the just described requirement. With respect to the comment that borrowers may be reluctant to share certain information with their auditors, this final rule specifically states that the provision of REA's security instrument requiring the submission of a report of the audit is not satisfied if the CPA must qualify the opinion in the auditor's report due to a scope limitation imposed by the borrower. The provision of the proposed rule relating to the availability of audit-related documents is adopted by this final rule.

Comment. Some commenters state that workpapers should only be made available to OIG and GAO through REA.

Response. Departmental Regulation 1700–1 requires REA to provide OIG and GAO access to all audit-related documents. Providing access through REA would only increase the administrative burden associated with this requirement. The proposal provision relating to availability of audit-related documents is adopted by this final rule.

Comment. One commenter argues that providing access to audit-related documents to OIG and GAO breaches the basic auditor-client confidential relationship.

Response. Rule 301, Confidential Client Information, of the AICPA's Code of Professional Conduct states, in part:

> A member in public practice shall not disclose any confidential client information without the specific consent of the client.

This final rule requires the audit agreement between a borrower and CPA to state that all audit-related documents, including auditors' reports, workpapers, and management letters, must be made available to REA, OIG, and GAO, upon request. The CPA should consider this provision before entering into an audit agreement with a borrower. By executing an audit agreement containing this provision, the CPA and borrower mutually agree that the CPA must provide access to REA, OIG, and GAO to all audit-related documents. As a result, the CPA, with the consent of the borrower as required by rule 301, will have knowingly and voluntarily waived any basis for keeping audit-related documents confidential. This final rule adopts the access to audit-related documents provision as proposed.

Comment. One commenter states that providing access to OIG and GAO violates the express language of the professional standards issued by the AICPA.

Response. Rule 301, Confidential Client Information, of the AICPA's Code of Professional Conduct prohibits disclosure by the CPA of confidential client information except under certain limited circumstances. One of those excepted circumstances is where the CPA has obtained the specific consent of the client. As stated in the last response, this final rule requires the audit agreement between a borrower and CPA to state that all audit-related documents must be made available to REA, OIG, and GAO, upon request. By executing an audit agreement that contains this provision, the borrower consents to the CPA's providing access to REA, OIG, and GAO to all audit-related documents. As a result, there is no conflict between the professional standards issued by the AICPA and this final rule. This final rule adopts the provision of the proposed rule relating to access to audit-related documents.

Communications With the Board of Directors

Comment. SAS No. 61 requires the auditor to communicate with an audit committee or its equivalent. If an audit committee or its equivalent does not exist, SAS No. 61 requires no communication. Several commenters state that the proposed rule unnecessarily expands the requirements of SAS No. 61 by requiring the auditor to communicate directly with the board of directors.

Response. The borrower's board of directors has the responsibility for the overall management of operations and the selection of a qualified CPA to perform the annual audit. A borrower's financial strength and, ultimately, REA's loan security is best served if the body responsible for management is kept fully informed of all matters affecting operations. It is, therefore, essential for the auditor to communicate directly with the board of directors. As a result, this requirement is adopted in this final rule.

Comment. The proposed rule states that the CPA would report all audit findings to the board of directors. One non-accountant commenter indicates that the term audit finding was not defined in the proposed rule.

Response. While not defined in the proposed rule, the term audit finding is universally understood among CPAs and to provide a specific definition could limit the CPA's use of professional judgment.

Comment. Several commenters recommend that only material audit findings be reported to the board of directors.

Response. As previously stated, a borrower's financial strength and, ultimately, REA's loan security is best

served if the body responsible for management activities is fully informed of all matters affecting operations. For this reason, it is essential for the board of directors to be aware of all findings resulting from the conduct of the audit, regardless of materiality.

Scope Limitations

Comment. The proposed rule includes a requirement that the CPA notify REA if a borrower imposed scope limitation prevents the issuance of an unqualified audit opinion. Two commenters indicate that the CPA should notify management, instead of REA. Another commenter indicates that management should notify REA. Two other commenters indicate that REA should be notified only if the borrower fails to take timely and appropriate actions to remove the scope limitation. Other commenters suggest that REA should be notified only after the issue is raised with the board of directors.

Response. An auditor's report that is qualified due to a scope limitation indicates that, at a minimum, a certain portion of the borrower's records are unavailable for audit, thereby significantly reducing the value of the report to REA. It is in REA's best interests, therefore, to work with the borrower to ensure that a scope limitation is removed. Based on the facts particular to each situation, the auditor must exercise professional judgment in determining what levels of management must be informed before notifying REA. Because the borrower has failed to make certain records available for audit, REA believes that it is essential to have an independent, third party notification of this fact. Only scope limitations that were not positively resolved with the borrower, however, must be reported. The proposal provision concerning scope limitations is adopted by this final rule.

Director's Salaries

Comment. The proposed rule includes a requirement that the auditor state whether provisions of the standard REA security instrument relating to the payment of salaries to the board of directors have been complied with. One commenter states that auditors cannot make a legal determination of what constitutes salary under the security instrument and recommends that REA provide a definition of salary together with specific examples.

Response. REA agrees with the comment. A definition of the term salary, for purposes of REA's security instrument, will be proposed in a future rulemaking separate and apart from this final rule. If REA determines that compliance reporting by the CPA is necessary when the definition of salary is adopted, part 1773 will be amended. This requirement is not adopted by this final rule.

Supplemental Lenders

Comment. Two commenters state that the proposed requirement to furnish the auditor's report to each supplemental lender is unnecessary, as it is included in the borrower's security instrument.

Response. REA agrees that including a requirement for borrowers to furnish reports to supplemental lenders is redundant. This requirement is not adopted by this final rule.

Comment. The proposed rule includes a requirement that the borrower notify supplemental lenders, if applicable, of the initial selection or subsequent change of a CPA. Two commenters suggest deleting this requirement.

Response. REA agrees that including a requirement for borrowers to furnish reports to supplemental lenders is redundant. This requirement is not adopted by this final rule.

Deferred Charges/Credits

Comment. Three commenters state that the proposed rule would require an auditor to report deferred charges and deferred credits, and argue that this requirement duplicates the information required by REA for approval of deferrals. If the requirement is adopted in this final rule, the commenters recommend limiting the reporting requirements to regulatory created assets and liabilities.

Response. This final rule adopts the recommendation to limit a CPA's reporting requirements to those regulatory created assets and liabilities that have not received REA approval. However, a requirement to report instances where REA approval has not been obtained is clearly separate and apart from any informational requirements REA may impose in order to enable it to determine whether to grant such approval. As a result, there is no reporting duplication.

Continuing Professional Education

Comment. One commenter suggests that the proposed continuing professional education requirements be revised to reflect those required for a GAGAS audit.

Response. REA agrees with the comment. This final rule adopts the continuing professional education requirements for a GAGAS audit.

Definition of Reportable Condition

Comment. One commenter requests that REA adopt a definition of reportable condition in this final rule.

Response. This final rule adopts a definition of reportable condition.

Peer Review Reports

Comment. The proposed rule includes a provision that the CPA submit to REA a copy of any peer review report and accompanying letter of comment, if any, within 60 days of the date of receipt of such report and letter of comment. One commenter indicates that the CPA is not permitted to distribute the peer review report until it is accepted by the peer review committee and suggests that this final rule base the submission requirement on the date the report is accepted by the peer review committee.

Response. This final rule adopts this provision.

Comment. The proposed rule includes a provision that requires a CPA who receives a qualified or adverse peer review report to undergo a second peer review within 18 months of the date of the qualified or adverse report. One commenter suggests that the need and timing of the second peer review should be determined by the Peer Review Committee of the SEC Practice Section of the Division for CPA Firms of the AICPA.

Response. The vast majority of CPAs who perform audits in the REA program do not participate in the SEC Practice Section of the AICPA thereby making this recommendation infeasible.

Documentation Requirements

Comment. The proposed rule includes a provision that requires audit documentation to be prepared in accordance with the professional standards of the AICPA and the requirements of this final rule. Two commenters indicate that the proposed rule does not specify which standard prevails should there be a conflict.

Response. No conflicts exist between the professional standards of the AICPA, GAGAS and REA requirements. REA has, however, imposed certain additional requirements that may exceed those prescribed by the AICPA or GAGAS.

Auditor's Report

Comment. One commenter indicates that the term audit report should be changed to auditor's report in order to correspond to SAS No. 58, Reports on Audited Financial Statements.

Response. REA agrees with the comment and this final rule adopts the term auditor's report. It should be noted,

however, that the report of the audit referred to in the REA security instrument consists of the auditor's report, report on compliance, report on internal controls, and management letter.

Comment. Several commenters argue that not accepting an annual report in lieu of an auditor's report creates unnecessary additional effort and expense for the CPA and borrower.

Response. In addition to the audited financial statements and the auditor's report, the annual report includes management's report on the year's operations and its forecast for the future. This information is based on opinion and speculation and is not independently confirmed by the CPA. As a result, this information should not be submitted to REA.

Borrower's Responsibilities

Comment. One commenter recommends that proposed § 1773.3, Borrower's Responsibilities, be revised to include the (1) preparation of financial statements in accordance with generally accepted accounting principles (GAAP); (2) execution of policies, procedures, and management processes adequate to protect material assets and detect significant failures to comply with pertinent regulations; (3) adoption of cost-effective auditor recommendations; and (4) reporting indications of material irregularities to all mortgagees.

Response. While REA agrees that it is the borrower's responsibility to prepare financial statements in accordance with GAAP and to execute policies, procedures, and management processes adequate to protect material assets and detect significant failures to comply with pertinent regulations, this final rule is not the appropriate vehicle in which to express these concerns. This final rule sets forth the borrower's responsibilities with regard to the annual audit and the above mentioned responsibilities extend beyond the scope of this section and the rule taken as a whole. Therefore, this final rule does not adopt this recommendation.

Timing of Submissions to REA

Comment. Several commenters argue that only the auditor's report should be submitted to REA within 120 days of the as of audit date. These commenters argue that the report on internal controls, the report on compliance, and the management letter require more time to review and should, therefore, be submitted within 180 days of the as of audit date.

Response. Submitting copies of the aforementioned reports and management letter to REA should not hinder the borrower's review process. REA has a legitimate and substantial interest in receiving these reports and management letter on a timely basis. REA does not consider the submission of these reports within 180 days to be timely; therefore, this final rule does not adopt the recommendation concerning the timing of the submission to REA.

Comment. Several commenters voice concern over the time constraints imposed by REA for borrowers to submit a plan of corrective action. Some commenters note that in many instances, the borrower does not receive the auditor's report until 90 days after the as of audit date. The proposed rule would require a plan for corrective action to be submitted within 4 months of the as of audit date, thereby allowing only 30 days for the borrower to act. Many commenters request an extension of the filing deadline to 180 days from the as of audit date.

Response. REA has reevaluated the time constraints of the proposed rule and agrees with the commenters that 180 days from the as of audit date is a more reasonable filing deadline. This provision is adopted by this final rule.

Change in the Name of a CPA Firm

Comment. One commenter argues that the change in the name of a CPA firm should not be deemed a change in the CPA firm.

Response. A change in the name of a CPA firm usually indicates that a change in the personnel controlling the firm has taken place. Consequently, a name change may impact on the firm's licensing and peer review requirements. REA must ensure that the new firm has met these requirements before approving the firm to audit an REA borrower. It is necessary, therefore, that REA be notified of all name changes.

Definition of Indirect Financial Interest

Comment. One non-accountant commenter states that REA should provide a definition of indirect financial interest in this final rule.

Response. The term indirect financial interest is used by the AICPA to determine whether a CPA is independent. The AICPA renders opinions on questions of independence, including what constitutes an indirect financial interest. Therefore, it is unnecessary for REA to separately define this term.

Capital Budgets

Comment. One commenter suggests that the value of the management letter would increase if it included explanations of differences between annual operations and capital budgets.

Response. REA does not wish to collect this information. However, supplemental lenders are free to develop whatever audit and reporting requirements they deem appropriate to implement the requirements of the security instrument.

Block Sampling

Comment. Several commenters state that the proposed requirement for the CPA to test one month's work order activity constitutes a block sample. A block sample with only one block is not adequate sampling as required by the AICPA.

Response. REA agrees with the comment and has eliminated the requirement for the CPA to test only one month's work order activity. The final rule requires the auditor to use his or her professional judgment to select a sample size adequate to reach an informed audit conclusion.

Pursuant to the Administrative Procedures Act (5 U.S.C. 553), it is found that good cause exists for not postponing the effective date of this final action until 30 days after publication in the **Federal Register** and for making this final rule effective as of December 31, 1991, because approximately 75% of the REA borrowers have established fiscal years ending as of December 31. By making this final rule effective on December 31, 1991, it will eliminate any confusion or uncertainty for the borrowers and their CPAs as to which audit requirements prevail. Accordingly, this final rule is effective as of December 31, 1991.

List of Subjects in 7 CFR Part 1773

Accounting, Electric power, Loan programs—communications, Loan programs—energy, Reporting and recordkeeping requirements, Rural areas, Telephone.

For the reasons set out in the preamble, title 7 part 1773 of the Code of Federal Regulations is revised as follows:

PART 1773—POLICY ON AUDITS OF REA BORROWERS

Subpart A—General Provisions

Subpart B—REA Audit Requirements

Authority: (7 U.S.C. 901 et seq.; 7 U.S.C. 1921 et seq.)

Subpart A—General Provisions

§ 1773.1 General.

(a) This part implements those standard provisions of the security instrument utilized by the Rural Electrification Administration (REA) for both electric and telephone borrowers and by the Rural Telephone Bank (RTB) for its telephone borrowers. The provisions require borrowers to prepare and furnish to REA, at least once during each 12-month period, a full and complete report of its financial condition, operations, and cash flows, in form and substance satisfactory to REA, audited and certified by an independent certified public accountant (CPA), satisfactory to REA, and accompanied by a report of such audit, in form and substance satisfactory to REA.

(b) This part 1773 applies to both REA and RTB borrowers. For the purposes of RTB borrowers, as used in this part 1773, *REA* means *RTB* and *Administrator* means *Governor* unless the text indicates otherwise.

(c) This part complies with Government Auditing Standards, Standards for Audit of Governmental Organizations, Programs, Activities, and Functions, 1988 revision, issued by the Comptroller General of the United States, United States General Accounting Office.

(d) An auditor's report, report on compliance, report on internal controls, and management letter are required to meet the reporting provisions of the REA security instrument.

(1) The auditor's report must state that the audit was conducted in accordance with generally accepted government auditing standards (GAGAS).

(2) The management letter must state that the audit was conducted in accordance with this part.

(3) A report of the audit, in form and substance satisfactory to REA, cannot be issued unless and until an audit has been performed in accordance with GAGAS and this part.

(4) A borrower is in violation of provisions of its security instrument with REA if the borrower fails to provide an audit performed in compliance with GAGAS and this part. REA security instruments normally provide for notice and an opportunity to cure such violations before REA can exercise certain remedies.

(5) A report prepared in connection with a review or compilation of financial statements, as defined in Statement of Standards for Accounting and Review Services No. 1, Compilation and Review of Financial Statements, does not satisfy the requirements of the REA security instrument.

(6) A report, as described in Statement on Auditing Standards (SAS) No. 62, entitled "Special Reports", or in SAS No. 35, entitled "Special Reports—Applying Agreed-upon Procedures to Specified Elements, Accounts, or Items of a Financial Statement", does not satisfy the REA loan security instrument requirements.

(7) An annual report containing audited financial statements does not satisfy the REA security instrument requirements.

(e) This part further implements those provisions of the standard REA security instrument by setting forth the criteria for CPAs to be deemed satisfactory to REA and the audit procedures and documentation standards that must be performed before a report of the audit satisfactory to REA can be prepared and issued.

§ 1773.2 Definitions.

As used in this part:

Administrator means the Administrator of REA and, as provided in § 1773.2 (b), *Governor*.

Audit means an examination of financial statements by an independent CPA for the purpose of expressing an opinion on the fairness with which those statements present financial position, results of operations, and changes in cash flows in conformity with generally accepted accounting principles (GAAP) and for determining whether the borrower has complied with applicable laws, regulations, and contracts for those transactions and events reflected in the financial statements.

AICPA means the American Institute of Certified Public Accountants.

BAD means the Borrower Accounting Division of REA.

CPA means certified public accountant. The terms *CPA* and *CPA firm* are used interchangeably.

FFB means the Federal Financing Bank, an instrumentality and wholly owned corporation of the United States.

GAAP means generally accepted accounting principles.

GAGAS means generally accepted government auditing standards as set forth in Government Auditing Standards, Standards for Audit of Governmental Organizations, Programs, Activities, and Functions, issued by the Comptroller General of the United States.

GAO means the General Accounting Office.

Governor means the Governor of the RTB.

Illegal act has the meaning prescribed in SAS No. 54, entitled "Illegal Acts by Clients".

Irregularity has the meaning prescribed in SAS No. 53, entitled "The Auditor's Responsibility to Detect and Report Errors and Irregularities".

OIG means the Office of Inspector General, United States Department of Agriculture.

OMB means the Office of Management and Budget.

PCPS means the Private Companies Practice Section of the AICPA.

REA means the Rural Electrification Administration, an agency of the United States Department of Agriculture and, as provided in § 1773.2(b), *RTB*.

Regulatory asset means an asset resulting from an action of a regulator as prescribed in Statement of Financial Accounting Standards (SFAS) No. 71, entitled "Accounting for the Effects of Certain Types of Regulation".

Regulatory liability means a liability imposed on a regulated enterprise by an

action of a regulator as prescribed in SFAS No. 71, entitled "Accounting for the Effects of Certain Types of Regulation".

Related party has the meaning prescribed in SFAS No. 57, entitled "Related Party Disclosures".

Related party transaction has the meaning prescribed in SFAS No. 57, entitled "Related Party Disclosures".

Reportable condition has the meaning prescribed in SAS No. 60, entitled "Communication of Internal Control Structure Related Matters Noted in an Audit".

RTB means the Rural Telephone Bank.

SAS means Statement on Auditing Standards as prescribed by the AICPA.

SEC Practice Section means the Securities and Exchange Commission Practice Section of the AICPA.

SFAS means Statements of Financial Accounting Standards as prescribed by the Financial Accounting Standards Board.

State means any state or territory of the United States, or the District of Columbia.

Uniform System of Accounts means, for telephone borrowers, the Uniform System of Accounts for Telecommunications Companies, prescribed by the Federal Communications Commission and set forth at 47 CFR part 32, as supplemented by REA pursuant to 7 CFR part 1770, Accounting Requirements for REA Telephone Borrowers, Subpart B, Uniform System of Accounts, and, for electric borrowers, the Uniform System of Accounts Prescribed for Electric Borrowers of the REA.

Subpart B—REA Audit Requirements

§ 1773.3 Annual audit.

(a) Each borrower must have its financial statements audited annually by a CPA selected by the borrower and approved by REA as set forth in § 1773.4.

(b) Each borrower must establish an annual as of audit date within twelve months of the date of receipt of the first advance of REA or FFB loan funds and must prepare financial statements as of the date established.

(c) Until all loans made or guaranteed by REA have been repaid, the borrower must furnish two copies of the auditor's report, report on compliance, report on internal controls, and management letter to REA within 120 days of the as of audit date.

(d) A borrower that qualifies as a unit of state or local government or Indian tribe as such terms are defined in the Single Audit Act of 1984 (31 U.S.C. 7501 et seq.) and OMB Circular A–128, Audits of State and Local Governments, must comply with this part as follows:

(1) A borrower that receives total Federal financial assistance equal to or in excess of $100,000 during the fiscal year, must have an audit performed and submit an auditor's report meeting the requirements of the Single Audit Act of 1984 (31 U.S.C. 7501 et seq.).

(2) A borrower that receives total Federal financial assistance of between $25,000 and $100,000 during the fiscal year must have an audit performed in accordance with either the requirements of the Single Audit Act of 1984 (31 U.S.C. 7501 et seq.) or this part.

(3) A borrower that receives less than $25,000 in total Federal financial assistance during the fiscal year must have an audit performed in accordance with the requirements of this part.

(4) A borrower must notify REA, in writing, within 30 days of the as of audit date, of the total Federal financial assistance received during the audit year and must state whether it will have an audit performed in accordance with the Single Audit Act of 1984 (31 U.S.C. 7501 et seq.) or this part.

(i) A borrower that elects to comply with this part must select a CPA that meets the qualifications set forth in § 1773.5.

(ii) If an audit is performed in accordance with the Single Audit Act of 1984 (31 U.S.C. 7501 et seq.), an auditor's report that meets the requirements of the Single Audit Act of 1984 (31 U.S.C. 7501 et seq.) will be sufficient to satisfy that borrower's obligations under this part.

(e) OMB Circular A–133, Audits of Institutions of Higher Education and Other Nonprofit Organizations, does not apply to audits of REA borrowers.

§ 1773.4 Borrower responsibilities.

(a) *Selection of a qualified CPA.* The borrower's board of directors is responsible for the selection of a qualified CPA that meets the requirements set forth in § 1773.5. When selecting a CPA, the borrower should consider, among other matters:

(1) The qualifications of CPAs available to do the work;

(2) The CPA's experience in performing audits of utilities; and

(3) The CPA's ability to complete the audit and submit the reports and management letter within 90 days of the as of audit date.

(b) *Board approval of selection.* The board's approval of a CPA must be recorded by a board resolution that states:

(1) The CPA meets REA's qualifications to perform an audit; and

(2) The borrower and CPA will enter into an audit agreement in accordance with § 1773.6.

(c) *Notification of selection.* When the initial selection or subsequent change of a CPA by a borrower has been made, the borrower must notify REA, in writing, at least 90 days prior to the as of audit date.

(1) REA will notify the borrower, in writing, within 30 days of the date of receipt of such notice, if the selection or change in CPA is not satisfactory.

(2) Notification to REA that the same CPA has been selected for succeeding audits of the borrower's financial statements is not required; however, the procedures outlined in this part must be followed for each new CPA selected, even though such CPA may previously have been approved by REA to audit records of other REA borrowers. Changes in the name of a CPA firm are considered to be a change in the CPA.

(d) *Audit agreement.* The borrower must enter into an audit agreement with the CPA that complies with § 1773.6.

(e) *Debarment certification.* The borrower is responsible for the receipt, from the selected CPA, of a lower tier covered transaction certification, as required under the provisions of Executive Orders 12549 and 12689, Debarment and Suspension, and any rules or regulations issued thereunder.

(f) *Submission of auditor's report.* The borrower must submit to REA the required auditor's report, report on compliance, report on internal controls, and management letter as set forth in § 1773.21.

(1) An annual auditor's report, report on compliance, report on internal controls, and management letter that fail to meet the requirements detailed in this part will be returned to the borrower with a written explanation of noncompliance.

(2) The borrower must, within 60 days of the date of the letter detailing the noncompliance, submit corrected reports to REA.

(3) If corrected reports are not received within 60 days of the date of the letter detailing the noncompliance, REA may notify the borrower that a default has occurred under its security instrument or take other appropriate action. The default notice will set forth the period of time during which the default will be remedied.

(g) *Submission of plan of corrective action.* The borrower must submit written comments to REA on the findings and recommendations in the auditor's report, report on compliance, report on internal controls, and

management letter. The borrower must also submit to REA:

(1) A written plan for corrective action taken or planned; and

(2) Comments on the status of corrective action taken on previously reported findings and recommendations.

If corrective action is not necessary, a written statement describing the reason it is not should accompany the auditor's report.

§ 1773.5 Qualifications of CPA.

For purposes of the REA standard security instrument, any CPA that meets the qualifications criteria of this section and enters into an audit agreement with the borrower that complies with § 1773.6, will be considered satisfactory to REA.

(a) *Certification.* The accountant that audits the financial statements of an REA borrower must be a CPA in good standing of some state. The CPA does not have to be licensed by the state in which the borrower is located; however, the CPA must abide by the rules and regulations of professional conduct promulgated by the accountancy board of the state in which the borrower is located.

(b) *Independence.* The CPA must be independent. A CPA will be considered independent if the CPA:

(1) Meets the standards for independence contained in the AICPA Code of Professional Conduct in effect at the time the CPA's independence is under review;

(2) Does not have and has not had any direct financial interest or any material indirect financial interest in the borrower during the period covered by the audit; and

(3) Is not and was not, during the period under audit, connected with the borrower as a promoter, underwriter, trustee, director, officer, or employee.

(c) *Peer review requirement.* The CPA must belong to and participate in a peer review program, and must have undergone a satisfactory peer review conducted by an approved peer review program under paragraph (c)(4) of this section. After the initial peer review has been performed, the CPA must submit to a peer review of the accounting and audit practice every three years or at such additional times as designated by the peer review executive committee.

(1) A CPA that receives an unqualified peer review report will be satisfactory to REA provided that the CPA meets the other criteria set forth in this section.

(2) If a CPA receives a qualified or adverse peer review report, the CPA must undergo a second peer review within 18 months of the date of the qualified or adverse report. A CPA that receives an unqualified second peer review report will be satisfactory to REA provided that the CPA meets the other criteria set forth in this section.

(3) A CPA that receives a second qualified or adverse peer review report will not be satisfactory to REA.

(4) Approved peer review programs. The following peer review programs are approved by REA:

(i) The peer review program conducted by the AICPA's Division for CPA Firms. (A CPA firm that selects this program must belong to either the PCPS or the SEC Practice Section);

(ii) The peer review program conducted by the regulated audit program group of the National Conference of CPA Practitioners; and

(iii) An independent peer review program that, in REA's determination, requires its members to:

(A) Ensure that the CPA can legally engage in the practice of certified public accounting;

(B) Adhere to the quality control standards established by the AICPA Quality Control Standards Committee that are in effect at the time of REA's determination;

(C) Submit to peer reviews of the CPA's accounting and audit practice every three years or at such additional times as designated by its own executive committee; and

(D) Ensure that all professionals in the firm, including CPAs and nonCPAs, take part in the qualifying continuing professional education requirements of GAGAS, as follows:

(*1*) An auditor responsible for planning, directing, conducting, or reporting on government audits must complete, every two years, at least eighty hours of continuing education and training which contributes to the auditor's professional proficiency. At least twenty hours must be completed in any one year of the two-year period; and

(*2*) An individual responsible for planning, directing, and conducting substantial portions of the field work, or reporting on the government audit must complete at least 24 of the 80 hours of continuing education and training in subjects directly related to the government environment and to government auditing. If the audited entity operates in a specific or unique environment, auditors must receive training that is related to that environment.

A qualified continuing professional education course is one which meets the standards of the PCPS.

(5) Notification. The CPA must notify the Director, BAD, in writing, of participation in a peer review program. REA will notify the CPA within 60 days of receipt of this notice if the selected peer review program is acceptable.

(6) Submission of reports. The CPA must submit to the Director, BAD, a copy of any peer review report and accompanying letter of comment, if any, within 60 days of the date such report and letter of comment are released by the peer review group.

(i) If the peer review report indicates that a follow-up review will be made, the CPA must submit subsequent reports to the Director, BAD, within 60 days of the date such reports are released by the peer review group.

(ii) A peer review report must be submitted to the Director, BAD, at least once every three years, or more frequently, if required by the peer review program.

(iii) A copy of the peer review report, accompanying letter of comment, and partners' inspections must be made available to OIG, upon request.

(d) *Audit agreement.* The CPA must enter into an audit agreement with the borrower that complies with § 1773.6.

§ 1773.6 Audit agreement.

(a) An audit agreement must be entered into by the CPA and the borrower and must include the following:

(1) The borrower and CPA acknowledge that the audit is being performed and the auditor's report, report on compliance, report on internal controls, and management letter is being issued in order to enable the borrower to comply with the provisions of REA's security instrument;

(2) The borrower and CPA acknowledge that REA regulations provide that if the borrower fails to have an audit performed and documented in compliance with GAGAS and this Part, the borrower is in violation of provisions of its security instrument with REA;

(3) The CPA represents that he/she meets the requirements under this Part to be satisfactory to REA;

(4) The CPA will perform the audit and will prepare the auditor's report, report on compliance, report on internal controls, and management letter in accordance with the requirements of this part;

(5) The CPA will document the audit work performed in accordance with the professional standards of the AICPA and the requirements of this part;

(6) The CPA will make all audit-related documents, including auditors' reports, workpapers, and management letters available to REA or its representatives (OIG, and GAO), upon

request, and will permit the photocopying of all audit-related documents; and

(7) The CPA will follow the requirements of reporting irregularities and illegal acts as outlined in § 1773.9.

(b) The audit agreement may include such additional terms and conditions as the CPA and borrower deem appropriate, including, but not limited to:

(1) The CPA will report all audit findings to the board of directors as required in § 1773.20(b); and

(2) The auditor's report, report on compliance, report on internal controls, and management letter with copies for transmittal to REA, and supplemental lenders, if applicable, will be submitted to the borrower's board of directors within 90 days of the as of audit date;

(c) A copy of the audit agreement must be available at the borrower's office for inspection by REA personnel. One copy of the current audit agreement must be maintained in the CPA's workpapers or permanent file.

§ 1773.7 Audit standards.

(a) The audit must be performed in accordance with GAGAS and this Part. The audit must be performed in accordance with GAGAS in effect at the audit date unless the borrower is directed otherwise, in writing, by REA.

(b) The audit must include such tests of the accounting records and such other auditing procedures that are sufficient to enable the CPA to express an opinion on the financial statements and to issue the required reports on compliance and internal controls and the management letter.

(c) Audit scope limitation. (1) The borrower will not limit the scope of the audit to the extent that the CPA is unable to meet REA's audit requirements or to provide an unqualified opinion that the financial statements are presented fairly in conformity with GAAP.

(2) The security instrument provision requiring the submission of a report of the audit is not satisfied if the CPA must qualify the opinion in the auditor's report due to limitations placed on the scope of the audit by the borrower.

(3) If the CPA determines during the audit that an unqualified opinion cannot be issued due to a scope limitation imposed by the borrower, the CPA should use professional judgment to determine what levels of the borrower's management should be informed.

(4) After informing the borrower's management, if the scope limitation is not adequately resolved, the CPA should immediately contact the Director, BAD, REA, U.S. Department of Agriculture, Washington, DC 20250-1500. The Director, BAD, will endeavor to resolve the matter with the borrower.

§ 1773.8 Audit date.

(a) The annual audit must be performed as of the end of the same calendar month each year unless prior approval to change the as of audit date is obtained, in writing, from REA.

(1) A borrower may request a change in the as of audit date by writing to the appropriate REA regional office at least 60 days prior to the newly requested as of audit date.

(2) The time period between the prior as of audit date and the newly requested as of audit date must be no longer than twenty-four months. For example, a borrower that wishes to change its as of audit date from December 31, 19X1, to June 30, must make the change effective no later than June 30, 19X3.

(b) Comparative financial statements must be prepared and audited for the twelve months ending as of the new audit date and for the twelve months immediately preceding that period.

(c) A borrower that changes its as of audit date from December 31, 19X1, to June 30, 19X3, must have the CPA report on statements in the following manner:

Previously issued statements	Statements prepared as of new audit date
12/31/X1; 12/31/X0 (Statements need not be reissued).	6/30/X3; 6/30/X2

§ 1773.9 Disclosure of irregularities and illegal acts.

(a) In accordance with GAGAS, the CPA must design audit steps and procedures to provide reasonable assurance of detecting errors, irregularities, and illegal acts that could have a direct and material effect on financial statement amounts.

(b) If there is an indication that an irregularity may have occurred, the CPA must extend audit steps and procedures to obtain sufficient, competent evidential matter to determine whether, in fact, an irregularity has occurred and the possible effect on the borrower's financial statements.

(c) Pursuant to the terms of its audit agreement with the borrower, the CPA must immediately report, in writing, all irregularities and all indications or instances of illegal acts, whether material or not, to:

(1) The president of the borrower's board of directors;

(2) The Director, BAD; and

(3) OIG, as follows:

(i) For the States of Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia, Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Puerto Rico, Rhode Island, Vermont and the Virgin Islands, report to USDA-OIG-Audit, Northeast Region, Regional Inspector General, 6505 Belcrest Road, room 428-A, Hyattsville, Maryland 20782;

(ii) For the States of Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee, report to USDA-OIG-Audit, Southeast Region, Regional Inspector General, 401 W. Peachtree Street, NW., room 2328, Atlanta, Georgia 30365-3520;

(iii) For the States of Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin, report to USDA-OIG-Audit, Midwest Region, Regional Inspector General, 111 N. Canal Street, Suite 1130, Chicago, Illinois 60606;

(iv) For the States of Arkansas, Louisiana, New Mexico, Oklahoma, and Texas, report to USDA-OIG-Audit, Southwest Region, Regional Inspector General, 101 South Main, room 324, Temple, Texas 76501;

(v) For the States of Colorado, Iowa, Kansas, Missouri, Montana, Nebraska, North Dakota, South Dakota, Wyoming, and Utah, report to USDA-OIG-Audit, Great Plains Region, Regional Inspector General, P.O. Box 293, Kansas City, Missouri 64141; and

(vi) For the States of Alaska, Arizona, California, Hawaii, Idaho, Nevada, Oregon, Territory of Guam, Trust Territories of Pacific, and Washington, report to USDA-OIG-Audit, Western Region, Regional Inspector General, 555 Battery Street, room 511, San Francisco, California 94111.

§ 1773.10 Access to audit-related documents.

Pursuant to the terms of the audit agreement, the CPA must make all audit-related documents, including auditors' reports, workpapers, and management letters available to REA, or its designated representative, upon request and must permit REA, or its designated representative, to photocopy all audit-related documents.

§§ 1773.11-1773.19 [Reserved]

Subpart C—REA Requirements for the Submission and Review of the Auditor's Report, Report on Compliance, Report on Internal Controls, and Management Letter

§ 1773.20 CPA's submission of the auditor's report, report on compliance, report on internal controls, and management letter.

(a) *Time limit.* As soon as possible

after completion of the audit, but within 90 days of the as of audit date, the CPA should deliver the auditor's report, report on compliance, report on internal controls, and management letter to the president of the borrower's board of directors. As a minimum, copies should be provided for each member of the board of directors and the manager. Further, two copies must be provided to the borrower for transmittal to REA.

(b) *Communication with the board of directors.* In addition to providing sufficient copies of the auditor's report, report on compliance, report on internal controls, and management letter for each member of the borrower's board of directors, REA requires that the CPA report all audit findings to the borrower's board of directors. REA recommends that audit findings be communicated orally; however, the communication may be oral or written, at the borrower's discretion. If the information is communicated orally, the CPA must document the communication by appropriate memoranda or notations in the workpapers. If the CPA communicates in writing, a copy of the written communication must be included in the CPA's audit workpapers or permanent file.

(c) *Matters to be communicated.* Matters communicated to the board of directors must include, but are not limited to the matters to be communicated to the audit committee as prescribed in SAS No. 61, entitled "Communication with Audit Committee",:

(1) The initial selection of and changes in significant accounting policies;

(2) The methods used to account for significant or unusual transactions and the effects of significant accounting policies in controversial or emerging areas;

(3) The process utilized by management to formulate significant accounting estimates and the basis for the CPA's conclusions regarding the reasonableness of these estimates;

(4) Audit findings and recommendations, including audit adjustments that either individually or in the aggregate have a significant effect on the borrower's financial statements;

(5) The CPA's responsibility for other information presented with the audited financial statements, any audit procedures performed, and the results thereof;

(6) Any disagreements with management, whether or not satisfactorily resolved, concerning matters that individually or in the aggregate may be significant to the borrower's financial statements or the auditor's report, report on compliance, report on internal controls, or management letter;

(7) Significant matters that were the subject of consultations with other accountants;

(8) Significant issues discussed with management with regard to the initial or recurring retention of the CPA; and

(9) Any serious difficulties encountered in dealing with management during the performance of the audit.

§ 1773.21 Borrower's review and submission of the auditor's report, report on compliance, report on internal controls, and management letter.

(a) The borrower's board of directors should note and record receipt of the auditor's report, report on compliance, report on internal controls, and management letter and any action taken in response to the reports or management letter in the minutes of the board meeting at which such reports and management letter are presented.

(b) The borrower must furnish REA with two copies of the auditor's report, report on compliance, report on internal controls, and management letter within 120 days of the as of audit date. Any provision in REA's security instrument that requires such documents to be furnished to REA in a shorter period of time may be disregarded.

(c) The borrower must furnish REA with two copies of its plan for corrective action, if any, within 180 days of the as of audit date.

(d) The borrower must furnish REA, within 120 days of the as of audit date, with a copy of each special report, summary of recommendations or similar communications, if any, received from the CPA as a result of the audit.

§§ 1773.22–1773.29 [Reserved]

Subpart D—REA Reporting Requirements

§ 1773.30 General.

(a) The CPA must prepare the following:

(1) An auditor's report, examples of which are set forth in appendixes A, exhibit 1 (Electric), and B, exhibit 1 (Telephone) of this part 1773;

(2) A report on compliance, examples of which are set forth in appendixes A, exhibits 2 through 4 (Electric) and B, exhibits 2 through 4 (Telephone) of this part 1773;

(3) A report on internal controls, examples of which are set forth in appendixes A, exhibits 5 and 6 (Electric) and B, exhibits 5 and 6 (Telephone) of this part 1773; and

(4) A management letter, an example of which is set forth in appendix C of this part 2773.

(b) The CPA should deliver the auditor's report, report on compliance, report on internal controls, and management letter (with copies as required in § 1773.20) to the borrower as soon as possible after completion of the audit but not more than 90 days after the as of audit date.

§ 1773.31 Auditor's report.

The CPA must prepare a written report on comparative balance sheets, statements of revenue and patronage capital (or income and retained earnings, depending upon the structure of the borrower) and statements of cash flows. The report must cover all statements presented.

§ 1773.32 Report on compliance.

(a) As required by GAGAS, the CPA must prepare a written report on the tests performed for compliance with applicable laws, regulations, and contracts. In accordance with the provisions of SAS No. 63, entitled "Compliance Auditing Applicable to Governmental Entities and Other Recipients of Governmental Financial Assistance", this report must contain:

(1) A statement of positive assurance for those items which were tested for compliance and a statement of negative assurance for those items not tested; and

(2) The status of known but uncorrected significant or material findings and recommendations from prior audits that affect the current audit objective.

(b) If, based upon assessments of materiality and audit risk, the CPA concludes that it is not necessary to perform tests of compliance with laws, regulations, and contracts, the CPA must issue a report as illustrated in appendix A, exhibit 2 (Electric) and appendix B, exhibit 2 (Telephone) of this part 1773.

(c) If the CPA determines that testing for compliance with laws, regulations, and contracts is necessary, and no material instances of noncompliance are found, the CPA must issue a report as illustrated in appendix A, exhibit 3

(Electric), and appendix B, exhibit 3 (Telephone) of this part 1773.

(d) If material instances of noncompliance are found, the CPA must issue a report as illustrated in appendix A, exhibit 4 (Electric), and appendix B, exhibit 4 (Telephone) of this part 1773.

(e) Other nonmaterial instances of noncompliance should not be disclosed in the report on compliance but should be reported in a separate communication to the board of directors, preferably in writing. All such communications must be documented in the workpapers.

(f) If the CPA has issued a separate letter detailing immaterial instances of noncompliance, the report on compliance must be modified to include a statement such as:

We noted certain immaterial instances of noncompliance that we have reported to the management of (borrower's name) in a separate letter dated March 2, 19X0.

§ 1773.33 Report on internal controls.

(a) As required by GAGAS, the CPA must prepare a written report on the borrower's internal control structure and the assessment of control risk made as part of the financial statement audit. In accordance with the provisions of SAS No. 63, the report must include, as a minimum:

(1) The scope of the CPA's work to obtain an understanding of the borrower's internal control structure and in assessing the control risk;

(2) A description of the borrower's significant internal controls or control structure including the controls established to ensure compliance with the laws, regulations, and contracts that have a material impact on the financial statements;

(3) A description of the reportable conditions noted which include material weaknesses identified as a result of the CPA's work in understanding and assessing the control risk; and

(4) The status of known but uncorrected, significant or material findings and recommendations from prior audits that affect the current audit objective.

§ 1773.34 Management letter.

The CPA must prepare a management letter that includes, at a minimum, comments on:

(a) *Audit procedures.* State whether the audit has been performed in accordance with this part;

(b) *Special reports.* State whether any special reports, summaries of recommendations, or similar communications were furnished to the borrower's management during the course of the audit or during interim audit work, and provide a description of the information furnished;

(c) *Accounting and records.* Comment on the adequacy and effectiveness of the borrower's accounting procedures, discuss the general condition of the records, and outline any recommendations for improvement. Comment on the adequacy and fairness of the methods used in accumulating and recording labor, material, and overhead costs, and the distribution of these costs to construction, retirement, and maintenance or other expense accounts, and where appropriate, include:

(1) Whether subsidiary plant records agree with the controlling general ledger plant accounts;

(2) Whether construction clearing accounts are cleared promptly of costs of completed construction to the proper classified plant accounts and whether depreciation was accrued on such completed construction from the date the plant was placed in service;

(3) Whether retirements of plant are currently and systematically recorded and properly priced;

(4) Whether all costs associated with retirements of plant are properly accounted for in the accumulated provision for depreciation accounts and comment on any unusual charges or credits to such accounts; and

(5) Whether REA approval was obtained for a sale requiring such approval, and whether receipts from sales of plant, material or scrap were not handled in conformance with REA requirements.

(d) *Materials control.* Comment on the adequacy of the control over materials and supplies.

(1) When appropriate, comment on discrepancies between physical inventory, perpetual inventory records, and the general ledger balance.

(2) The comment should identify the dollar amount of gross overages and gross shortages, as well as the net amount of the discrepancy.

(3) The comment should indicate the disposition of any differences and include recommendations for disposition of deferred amounts remaining on the books at the close of the audit for which a satisfactory method of disposition has not been determined;

(e) *Compliance with REA loan and security instrument provisions.* State whether the following provisions of REA's loan and security instruments have been complied with:

(1) For electric borrowers, provisions relating to:

(i) The requirement for a borrower to maintain insurance (See 7 CFR part 1788, REA Fidelity and Insurance Requirements for Electric and Telephone Borrowers) and apply the insurance proceeds as prescribed;

(ii) The requirement for funds to be deposited in banks or other depositories designated in the loan documents or approved by REA;

(iii) The requirement for a borrower to obtain written approval of mortgagees to enter into any contract for the operation or maintenance of all or any part of its property, or for the use by others of its property; and

(iv) The requirement for a borrower to prepare and furnish mortgagees annual financial and statistical reports on the borrower's financial condition and operations. The CPA must state whether the information submitted to REA in the most recent December 31 REA Form 7 or Form 12 is in agreement with the borrower's records, and must comment on any exceptions noted. If an amended report has been filed as of December 31, the comments must relate to the amended report.

(2) For telephone borrowers, provisions relating to:

(i) The requirement for a borrower to maintain insurance (See 7 CFR part 1788) and apply insurance proceeds as prescribed;

(ii) The requirement for a borrower to obtain written approval of the mortgagees to enter into any contract for the operation or maintenance of property, for the use of mortgaged property by others, or for services pertaining to toll traffic, operator assistance, or switching;

(iii) The requirement for funds to be deposited in banks or other depositories designated in the loan documents or approved by REA; and

(iv) The requirement for a borrower to prepare and furnish mortgagees annual financial and statistical reports on the borrower's financial condition and operations. The CPA must state whether the information submitted to REA in the most recent December 31 REA Form 479 is in agreement with the borrower's records, and must comment on any exceptions noted. If an amended report has been filed as of December 31, the comments must relate to the amended report;

(f) *Related party transactions.* State whether all material related party transactions have been disclosed in the notes to the financial statements in accordance with SFAS No. 57, entitled "Related Party Disclosures". If the audit did not disclose any related party transactions considered to be material, either individually or in the aggregate, so state;

(g) *Depreciation rates.* For electric borrowers, comment when the depreciation rates used in computing monthly accruals are not in compliance with REA requirements (See REA Bulletin 183-1, Depreciation Rates and Procedures) or with the requirements of the state regulatory body having jurisdiction over the borrower's depreciation rates; and

(h) *Deferred debits and deferred credits.* For electric borrowers, provide a detailed analysis of the totals reported as deferred debits and deferred credits, including, but not limited to, margin stabilization plans, revenue deferral plans, and expense deferrals. The CPA must state whether REA has approved, in writing, each regulatory asset and liability.

§§ 1773.35–1773.37 [Reserved]

Subpart E—REA Required Audit Procedures and Documentation

§ 1773.38 Scope of engagement.

(a) REA requires that the audit procedures set forth in §§ 1773.39 through 1773.45 be performed annually by the CPA during the audit of the REA borrowers' financial statements, which audit procedures may be in addition to the conduct of a GAGAS audit.

(b) The CPA must exercise professional judgment in determining whether any auditing procedures in addition to those mandated by GAGAS or this part should be performed in order to afford a reasonable basis for rendering the auditor's report, report on compliance, report on internal controls, and management letter.

§ 1773.39 Utility plant and accumulated depreciation.

(a) *General.* The audit of these accounts must include tests of additions, replacements, retirements, and changes. Based upon the CPA's determination of materiality, an appropriate sample of transactions must be selected for testing. The CPA's workpapers must document that he/she:

(1) Examined direct labor and material transactions to determine whether the borrower's accounting records reflect a complete accumulation of costs;

(2) Examined indirect costs and overhead charges to determine if they conform to the Uniform System of Accounts;

(3) Reviewed the costs of completed construction and retirement projects to determine if they were cleared promptly from the work in progress accounts to the classified plant in service accounts and the related depreciation reserves;

(4) Examined direct purchases of special equipment and general plant;

(5) Determined the degree of accuracy and control of costing retirements, including tests of salvage and removal costs;

(6) Reviewed the borrower's work order procedures; and

(7) Reviewed depreciation rates for adequate support, compared them to REA guidelines, and determined if they are in compliance.

(b) *Construction work in progress.* (1) The workpapers must include a summary of open work orders reconciled to the general ledger. The CPA must note on the summary any unusual or nontypical projects.

(2) Based upon the CPA's determination of materiality, an appropriate sample of work orders must be selected for testing. The CPA's workpapers must document that he/she:

(i) Reviewed equipment purchases charged to work orders, including payments and receiving reports;

(ii) Reviewed contracts showing the scope of the work, the nature of the contract, the contract amount, and scheduled payments and reviewed supporting documents to determine that all services contracted for were in fact rendered;

(iii) Reviewed time cards and pay rates for several employees who allocate their time to work orders;

(iv) Reviewed the nature of material and supplies issued to the project, traced amounts and quantities to supporting documents, and reviewed the reasonableness of clearing rates for assignment of stores expense to the work order;

(v) Reviewed the accuracy of the computation of overheads applied to the work order; and

(vi) Reviewed other costs charged to the work order for support and propriety.

(3) Based upon the CPA's determination of materiality, an appropriate sample of completed contracts must be selected for testing. The CPA's workpapers must document that he/she:

(i) Scheduled payments to contractors and traced to verify payments and supporting invoices;

(ii) Traced contract costs to final closeout documents, to the general ledger, and to the continuing property records; and

(iii) Verified the costs of owner furnished materials, if applicable.

(4) The CPA must review the borrower's procedures for unitization and classification of work order and contract costs. Based upon the CPA's determination of materiality, an appropriate sample of transactions must be selected for testing. The CPA's workpapers must document that he/she:

(i) Reviewed the tabulation of record units for construction from the work order staking sheets to the tabulation of record units, to the unitization sheets, and to the continuing property records;

(ii) Reviewed the procedures for unitizing and distributing costs of completed construction to the plant accounts;

(iii) Verified that standard costs were being used;

(iv) Evaluated the basis for development of standard costs; and

(v) Determined that costs of completed construction were cleared promptly from work in progress accounts.

(c) *Continuing property records.* Based upon the CPA's determination of materiality, an appropriate sample of transactions must be selected for testing. The CPA's workpapers must document that he/she:

(1) Determined whether the subsidiary plant records agree with the controlling general ledger plant accounts;

(2) Noted differences in the workpapers; and

(3) Commented, in the management letter, on any discrepancies.

(d) *Retirement work-in-progress.* Based upon the CPA's determination of materiality, an appropriate sample of transactions must be selected for testing. The CPA's workpapers must document that he/she:

(1) Determined that plant retirements are currently and systematically recorded and priced on the basis of the continuing property records, and determined that costs of removal have been properly accounted for;

(2) Explained the method used in computing the cost of units of plant retired if continuing property records have not been established and determined whether costs appeared reasonable; and

(3) Determined the manner in which net losses due to retirements were accounted for and traced clearing entries to the depreciation reserve, the plant accounts, and the continuing property records.

(e) *Provision for accumulated depreciation.* The CPA's workpapers must include an analysis of transactions. Based upon the CPA's determination of materiality, an appropriate sample of transactions must be selected for testing. The CPA's workpapers must document that he/she:

(1) Verified the depreciation accruals for the period, including the depreciation base;

(2) Reviewed the basis of the depreciation rates, any change in rates and the reason therefor, and, if appropriate, determined whether the rates are in compliance with REA requirements or with the requirements of the state regulatory body having jurisdiction over the borrower's depreciation rates;

(3) Reviewed salvage and removal costs; and

(4) Searched for unrecorded retirements.

(f) *Other reserves.* The CPA's workpapers must include an account analysis for all other material plant reserves, such as the reserve for the amortization of plant acquisition adjustments. Based upon the CPA's determination of materiality, an appropriate sample of transactions must be selected for testing. The CPA's workpapers must document that appropriate tests of transactions were performed.

(g) *Narrative.* The CPA must prepare and include in the workpapers a comprehensive narrative on the scope of work performed, observations made, and conclusions reached. Specific matters covered in this narrative must include:

(1) The nature of construction and other additions;

(2) The control over, and the accuracy of pricing retirements;

(3) The accuracy of distributing costs to classified utility plant accounts;

(4) An evaluation of the method of:

(i) Capitalizing the direct loadings on labor and material costs;

(ii) Distributing transportation costs and other expense clearing accounts; and

(iii) Capitalizing overhead costs;

(5) The tests of depreciation;

(6) A review of agreements such as those relating to acquisitions, property sales, and leases which affect the plant accounts; and

(7) Notations, if applicable, of REA approval of property sales and the propriety of the disposition of the proceeds.

§ 1773.40 Regulatory assets.

The CPA's workpapers must document that all regulatory assets comply with the requirements of SFAS No. 71 and have received REA approval.

§ 1773.41 Extraordinary retirement losses.

The CPA's workpapers must contain an analysis of retirement losses, including any required approval by a regulatory commission with jurisdiction in the matter, or REA, in the absence of commission jurisdiction.

§ 1773.42 Clearing accounts.

The CPA's workpapers must contain an analysis of all clearing accounts. Based upon the CPA's determination of materiality, an appropriate sample of transactions should be selected for testing. The CPA's workpapers must document that transactions were reviewed for proper allocation between expense and capital accounts.

§ 1773.43 Capital and equity accounts.

(a) *Capital stock.* For privately owned companies, the workpapers must include analyses of all stock transactions during the audit period. Based upon the CPA's determination of materiality, an appropriate sample of transactions must be selected for testing. The CPA's workpapers must document that he/she:

(1) Reviewed the subsidiary records and reconciled them to the general ledger control account;

(2) Reviewed authorizations and issuances or redemptions of capital stock for proper approvals by the board of directors, stockholders, and regulatory commissions;

(3) Determined that transactions were made in accordance with the appropriate provisions of the articles of incorporation, bylaws, and REA loan documents; and

(4) Determined that transactions were recorded in accordance with the Uniform System of Accounts.

(b) *Memberships.* For cooperative organizations, the workpapers must include an analysis of the membership transactions during the audit period. Based upon the CPA's determination of materiality, an appropriate sample of transactions must be selected for testing. The CPA's workpapers must document that he/she:

(1) Reviewed the subsidiary records and reconciled them to the general ledger control account; and

(2) Determined that transactions were made in accordance with the appropriate provisions of the articles of incorporation, bylaws, and REA loan documents.

(c) *Patronage capital, retained earnings, margins, and other equities.* The workpapers must include an analysis of the patronage capital, retained earnings, margins and other equities, and any related reserve accounts. Based upon the CPA's determination of materiality, an appropriate sample of transactions must be selected for testing. The CPA's workpapers must document that he/she:

(1) Determined that the transactions were made in accordance with the appropriate provisions of the articles of incorporation, bylaws, REA loan documents, Uniform System of Accounts, or orders of regulatory commissions;

(2) Traced payments to underlying support; and

(3) Determined whether, under the terms of the REA security instrument, restrictions of retained earnings or margins are required and, if so, whether they have been properly recorded.

§ 1773.44 Long-term debt.

The CPA's workpapers must document that he/she:

(a) Confirmed REA, FFB, and RTB debt to the appropriate confirmation schedule (REA Form 690, Confirmation Schedule Obligation to the FFB as of: or Form 691, Confirmation Schedule—Long-term Obligation to REA as of; or RTB Form 12, Confirmation Schedule);

(b) Confirmed other long-term debt directly with the lender;

(c) Examined notes executed or canceled during the audit period; and

(d) Tested accrued interest computations.

§ 1773.45 Regulatory liabilities.

The CPA's workpapers must document that all regulatory liabilities comply with the requirements of SFAS No. 71 and have received REA approval.

§§ 1773.46–1773.49 [Reserved]

Appendix A to Part 1773—Sample Auditor's Report for an Electric Cooperative

Appendix A includes an example of an auditor's report, report on compliance, report on internal controls, financial statements and accompanying notes for an electric distribution cooperative. The sample auditor's report is intended as a guide only and, while it is recommended that the format be followed, each auditor's report should be prepared to adequately cover the circumstances. To the extent possible, it should be used as a guide in preparing auditors' reports for other types of electric borrowers. For power supply borrowers and for distribution borrowers with production or transmission plant, the same general format should be followed. However, the Statement of Revenue and Patronage Capital must be expanded to show separate totals for operations expenses and maintenance expenses for each class of production plant and for transmission plant.

Exhibit 1—Sample Auditor's Report

Certified Public Accountants, 1600 Main Street, City, State 24105, The Board of Directors, Center County Electric Cooperative

Independent Auditor's Report

We have audited the accompanying balance sheets of Center County Electric Cooperative as of December 31, 19X9 and 19X8, and the related statements of revenue and patronage capital, and cash flows for the

years then ended. These financial statements are the responsibility of the cooperative's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with generally accepted auditing standards and the Government Auditing Standards, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Center County Electric Cooperative as of December 31, 19X9 and 19X8, and the results of its operations and its cash flows for the years then ended in conformity with generally accepted accounting principles.

Certified Public Accountants, March 2, 19X0

Exhibit 2—Sample Report on Compliance When, Based on Assessments of Materiality and Audit Risk, the CPA Concluded It Was Not Necessary to Perform Tests of Compliance With Laws and Regulations

Certified Public Accountants, 1600 Main Street, City, State 24105, The Board of Directors, Center County Electric Cooperative

We have audited the financial statements of Center County Electric Cooperative as of and for the years ended December 31, 19X9 and 19X8, and have issued our report thereon dated March 2, 19X0.

We conducted our audit in accordance with generally accepted auditing standards and the Government Auditing Standards, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

Compliance with laws, regulations, contracts, and grants applicable to Center County Electric Cooperative is the responsibility of Center County Electric Cooperative's management. As part of our audit, we assessed the risk that noncompliance with certain provisions of laws, regulations, contracts, and grants could cause the financial statements to be materially misstated. We concluded that the risk of such material misstatement was sufficiently low that it was not necessary to perform tests of Center County Electric Cooperative's compliance with such provisions of laws, regulations, contracts, and grants.

However, in connection with our audit, nothing came to our attention that caused us to believe that Center County Electric Cooperative had not complied, in all material respects, with the laws, regulations, contracts, and grants referred to in the preceding paragraph.

This report is intended for the information of the audit committee, management, and the Rural Electrification Administration and supplemental lenders. This restriction is not intended to limit the distribution of this report, which is a matter of public record.

Certified Public Accountants, March 2, 19X0

Exhibit 3—Sample Report on Compliance When, Based on Assessments of Materiality and Audit Risk, the CPA Performed Compliance Testing and Found No Material Instances of Noncompliance

Certified Public Accountants, 1600 Main Street, City, State 24105, The Board of Directors, Center County Electric Cooperative

We have audited the financial statements of Center County Electric Cooperative as of and for the years ended December 31, 19X9 and 19X8, and have issued our report thereon dated March 2, 19X0.

We conducted our audit in accordance with generally accepted auditing standards and the Government Auditing Standards, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

Compliance with laws, regulations, contracts, and grants applicable to Center County Electric Cooperative is the responsibility of Center County Electric Cooperative's management. As part of obtaining reasonable assurance about whether the financial statements are free of material misstatement, we performed tests of Center County Electric Cooperative's compliance with laws, regulations, contracts, and grants. However, our objective was not to provide an opinion on overall compliance with such provisions.

The results of our tests indicate that, with respect to the items tested, Center County Electric Cooperative complied, in all material respects, with the provisions referred to in the preceding paragraph. With respect to items not tested, nothing came to our attention that caused us to believe that Center County Electric Cooperative had not complied, in all material respects, with those provisions.

This report is intended for the information of the audit committee, management, and the Rural Electrification Administration and supplemental lenders. This restriction is not intended to limit the distribution of this report, which is a matter of public record.

Certified Public Accountants, March 2, 19X0

Exhibit 4—Sample Report on Compliance When, Based on Assessments of Materiality and Audit Risk, the CPA Performed Compliance Testing and Found Material Instances of Noncompliance

Certified Public Accountants, 1600 Main Street, City, State 24105, The Board of Directors, Center County Electric Cooperative

We have audited the financial statements of Center County Electric Cooperative as of and for the years ended December 31, 19X9 and 19X8, and have issued our report thereon dated March 2, 19X0.

We conducted our audit in accordance with generally accepted auditing standards and the Government Auditing Standards, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

Compliance with laws, regulations, contracts, and grants applicable to Center County Electric Cooperative is the responsibility of Center County Electric Cooperative's management. As part of obtaining reasonable assurance about whether the financial statements are free of material misstatement, we performed tests of Center County Electric Cooperative's compliance with laws, regulations, contracts, and grants. However, our objective was not to provide an opinion on overall compliance with such provisions.

Material instances of noncompliance are failures to follow requirements or violations of prohibitions, contained in statutes, regulations, contracts, or grants that cause us to conclude that the aggregation of the misstatements resulting from those failures or violations is material to the financial statements. The results of our tests of compliance disclosed the following material instances of noncompliance, the effects of which have been corrected in Center County Electric Cooperative's 19X9 and 19X8 financial statements.

(Include paragraphs describing the material instances of noncompliance noted.)

We considered these material instances of noncompliance in forming our opinion on whether Center County Electric Cooperative's 19X9 and 19X8 financial statements are presented fairly, in all material respects, in conformity with generally accepted accounting principles, and this report does not affect our report dated March 2, 19X0 on those financial statements. Except as described above, the results of our tests of compliance indicate that, with respect to the items tested Center County Electric Cooperative complied, in all material respects, with the provisions referred to in the third paragraph of this report, and with respect to items not tested, nothing came to our attention that caused us to believe that Center County Electric Cooperative had not complied, in all material respects, with those provisions.

This report is intended for the information of the audit committee, management, and the Rural Electrification Administration and supplemental lenders. This restriction is not intended to limit the distribution of this report, which is a matter of public record.

Certified Public Accountants, March 2, 19X0

Exhibit 5—Sample Report on Internal Controls When Reportable Conditions Were Found

Certified Public Accountants, 1600 Main Street, City, State 24105, The Board of Directors, Center County Electric Cooperative

We have audited the financial statements of Center County Electric Cooperative as of and for the years ended December 31, 19X9 and 19X8, and have issued our report thereon dated March 2, 19X0.

We conducted our audit in accordance with generally accepted auditing standards and Government Auditing Standards, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

In planning and performing our audit of the financial statements of Center County Electric Cooperative for the years ended December 31, 19X9 and 19X8, we considered its internal control structure in order to determine our auditing procedures for the purpose of expressing our opinion on the financial statements and not to provide assurance on the internal control structure.

The management of Center County Electric Cooperative is responsible for establishing and maintaining an internal control structure. In fulfilling this responsibility, estimates and judgments by management are required to assess the expected benefits and related costs of internal control structure policies and procedures. The objectives of an internal control structure are to provide management with reasonable, but not absolute, assurance that assets are safeguarded against loss from unauthorized use or disposition, and that transactions are executed in accordance with management's authorization and recorded properly to permit the preparation of financial statements in accordance with generally accepted accounting principles. Because of inherent limitations in any internal control structure, errors or irregularities may nevertheless occur and not be detected. Also, projection of any evaluation of the structure to future periods is subject to the risk that procedures may become inadequate because of changes in conditions or that the effectiveness of the design and operation of policies and procedures may deteriorate.

For the purpose of this report, we have classified the significant internal control structure policies and procedures in the following categories (identify internal control structure categories).

For all of the internal control structure categories listed above, we obtained an understanding of the design of relevant policies and procedures and whether they have been placed in operation, and we assessed control risk. We noted certain matters involving the internal control structure and its operation that we consider to be reportable conditions under standards established by the American Institute of Certified Public Accountants. Reportable conditions involve matters coming to our attention relating to significant deficiencies in the design or operation of the internal control structure that, in our judgment, could adversely affect the entity's ability to record, process, summarize, and report financial data consistent with the assertions of management in the financial statements.

(Include paragraphs to describe the reportable conditions noted).

A material weakness is a reportable condition in which the design or operation of the specific internal control structure elements does not reduce to a relatively low level the risk that errors or irregularities in amounts that would be material in relation to the financial statements being audited may occur and may not be detected within a timely period by employees in the normal course of performing their assigned functions.

Our consideration of the internal control structure would not necessarily disclose all matters in the internal control structure that might be reportable conditions and, accordingly, would not necessarily disclose all reportable conditions that are also considered to be material weaknesses as defined above. However, we believe none of the reportable conditions described above is a material weakness.

We also noted other matters involving the internal control structure and its operation that we have reported to the management of Center County Electric Cooperative in a separate letter dated March 2, 19X0.

This report is intended for the information of the audit committee, management, and the Rural Electrification Administration and supplemental lenders. This restriction is not intended to limit the distribution of this report, which is a matter of public record.

Certified Public Accountants, March 2, 19X0

Exhibit 6—Sample Report on Internal Controls When No Reportable Conditions Were Found

Certified Public Accountants, 1600 Main Street, City, State 24105, The Board of Directors, Center County Electric Cooperative

We have audited the financial statements of Center County Electric Cooperative as of and for the years ended December 31, 19X9 and 19X8, and have issued our report thereon dated March 2, 19X0.

We conducted our audit in accordance with generally accepted auditing standards and Government Auditing Standards, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

In planning and performing our audit of the financial statements of Center County Electric Cooperative for the years ended December 31, 19X9 and 19X8, we considered its internal control structure in order to determine our auditing procedures for the purpose of expressing our opinion on the financial statements and not to provide assurance on the internal control structure.

The management of Center County Electric Cooperative is responsible for establishing and maintaining an internal control structure. In fulfilling this responsibility, estimates and judgments by management are required to assess the expected benefits and related costs of internal control structure policies and procedures. The objectives of an internal control structure are to provide management with reasonable, but not absolute, assurance that assets are safeguarded against loss from unauthorized use or disposition, and that transactions are executed in accordance with management's authorization and recorded properly to permit the preparation of financial statements in accordance with generally accepted accounting principles. Because of inherent limitations in any internal control structure, errors or irregularities may nevertheless occur and not be detected. Also, projection of any evaluation of the structure to future periods is subject to the risk that procedures may become inadequate because of changes in conditions or that the effectiveness of the design and operation of policies and procedures may deteriorate.

For the purpose of this report, we have classified the significant internal control structure policies and procedures in the following categories (identify internal control structure categories).

For all of the internal control structure categories listed above, we obtained an understanding of the design of relevant policies and procedures and whether they have been placed in operation, and we assessed control risk.

Our consideration of the internal control structure would not necessarily disclose all matters in the internal control structure that might be material weaknesses under standards established by the American Institute of Certified Public Accountants. A material weakness is a reportable condition in which the design or operation of one or more of the specific internal control structure elements does not reduce to a relatively low level the risk that errors or irregularities in amounts that would be material in relation to the financial statements being audited may occur and not be detected within a timely period by employees in the normal course of performing their assigned functions. We noted no matters involving the internal control structure and its operation that we consider to be material weaknesses as defined above.

However, we noted certain matters involving the internal control structure and its operation that we have reported to the management of Center County Electric Cooperative in a separate letter dated March 2, 19X0.

This report is intended for the information of the audit committee, management, and the Rural Electrification Administration and supplemental lenders. This restriction is not intended to limit the distribution of this report, which is a matter of public record.

Certified Public Accountants, March 2, 19X0

BILLING CODE 3410-15-M

EXHIBIT 7 - SAMPLE FINANCIAL STATEMENTS

CENTER COUNTY ELECTRIC COOPERATIVE
BALANCE SHEETS - DECEMBER 31, 19X9 AND 19X8
ASSETS (Notes 1 and 2)

	19X9	19X8
ELECTRIC PLANT: (Note 3)		
In Service - at cost	$9,524,646	$9,365,264
Construction Work in Progress	407,943	317,166
	9,932,589	9,682,430
Less: Accumulated Provisions for Depreciation	3,117,629	2,917,295
	6,814,960	6,765,135
OTHER ASSETS AND INVESTMENTS:		
Nonutility Property	20,227	20,227
Investments in Associated Organizations (Note 4)	391,258	292,798
	411,485	313,025
CURRENT ASSETS:		
Cash - General Funds	37,350	51,544
Cash - Construction Funds	10,034	20,193
Accounts Receivable (Less accumulated provision for uncollectible accounts of $2,207 in 19X9 and $1,933 in 19X8)	36,527	35,255
Materials and Supplies (at average cost)	83,652	80,882
Other Current and Accrued Assets	8,613	8,692
	176,176	196,566
DEFERRED CHARGES (Note 5):	5,666	1,762
	$7,408,287	$7,276,488

The accompanying notes are an integral part of these statements.

CENTER COUNTY ELECTRIC COOPERATIVE
BALANCE SHEETS - DECEMBER 31, 19X9 and 19X8
EQUITIES AND LIABILITIES (Note 1)

	19X9	19X8
EQUITIES:		
Memberships	$ 60,145	$ 59,440
Patronage Capital (Note 6)	1,761,798	1,526,833
Other Equities (Note 7)	53,647	35,900
	1,875,590	1,622,173
LONG-TERM DEBT:		
REA Mortgage Notes less current maturities (Note 8)	5,249,115	5,396,385
CURRENT LIABILITIES:		
Current Maturities of Long-Term Debt	145,000	140,000
Accounts Payable - Purchased Power	48,916	52,117
Accounts Payable - Other	21,859	6,556
Consumer Deposits	32,660	33,085
Accrued Taxes	10,958	9,146
Other Current and Accrued Liabilities	12,285	6,461
	271,678	247,365
DEFERRED CREDITS (Note 10):	11,904	10,565
	$7,408,287	$7,276,488

The accompanying notes are an integral part of these statements.

CENTER COUNTY ELECTRIC COOPERATIVE
STATEMENTS OF REVENUE AND PATRONAGE CAPITAL
FOR THE YEARS ENDED DECEMBER 31, 19X9 and 19X8

	19X9	19X8
OPERATING REVENUES:	$1,719,467	$1,605,690
OPERATING EXPENSES:		
Cost of Power	587,729	625,411
Distribution - Operation	111,058	121,682
Distribution - Maintenance	158,622	182,740
Consumer Accounts	76,675	72,927
Sales	38,378	40,755
Administrative and General	94,682	87,058
Depreciation and Amortization	288,389	279,776
Taxes	34,920	34,438
	1,390,453	1,444,787
OPERATING MARGINS BEFORE FIXED CHARGES	329,014	160,903
FIXED CHARGES:		
Interest on Long-Term Debt	113,713	115,082
OPERATING MARGINS AFTER FIXED CHARGES	215,301	45,821
G&T AND OTHER CAPITAL CREDITS	14,460	17,500
NET OPERATING MARGINS	229,761	63,321
NONOPERATING MARGINS:		
Interest Income	24,289	18,802
Other Nonoperating Income	1,200	1,200
	25,489	20,002
NET MARGINS	255,250	83,323
PATRONAGE CAPITAL - BEGINNING OF YEAR	1,526,833	1,469,125
	1,782,083	1,552,448
RETIREMENT OF CAPITAL CREDITS	20,285	25,615
PATRONAGE CAPITAL - END OF YEAR	$1,761,798	$1,526,833

The accompanying notes are an integral part of these statements.

CENTER COUNTY ELECTRIC COOPERATIVE
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 19X9 AND 19X8

	19X9	19X8
CASH FLOWS FROM OPERATING ACTIVITIES:		
Cash Received from Consumers	$1,721,496	$1,609,933
Cash Paid to Suppliers and Employees	(1,049,139)	(1,126,367)
Interest Received	24,289	18,802
Interest Paid	(114,131)	(115,607)
Taxes Paid	(33,108)	(32,132)
Net Cash Provided by Operating Activities	549,407	354,629
CASH FLOWS FROM INVESTING ACTIVITIES:		
Construction and Acquisition of Plant	(322,234)	(216,427)
Plant Removal Costs	(25,994)	(19,268)
Materials Salvaged from Retirements	10,014	7,327
(Increase)/Decrease In:		
Materials Inventory	(2,770)	1,916
Deferred Charges-Preliminary Survey & Investigation	(3,486)	(2,617)
Investments-CFC Capital Term Certificates	(82,472)	(69,412)
Inventory Adjustment-Deferred Credit Decrease	(2,290)	(1,057)
Net Cash Used in Investing Activities	(429,232)	(299,538)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Retirements of Patronage Capital Credits	(20,285)	(25,615)
Retired Capital Credits - Gain	1,200	1,200
Donated Capital	16,547	6,178
REA Loan Advances	174,976	197,450
Payments on REA Debt	(317,246)	(279,575)
Increase/(Decrease) In:		
Consumer Deposits	(425)	575
Memberships Issued	705	450
Net Cash Used in Financing Activities	(144,528)	(99,337)
Net Increase/(Decrease) in Cash	(24,353)	(44,246)
Cash - Beginning of Year	71,737	115,983
Cash - End of Year	$ 47,384	$ 71,737

The accompanying notes are an integral part of these statements.

CENTER COUNTY ELECTRIC COOPERATIVE
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 19X9 AND 19X8

RECONCILIATION OF NET MARGINS TO NET CASH PROVIDED BY OPERATING ACTIVITIES:

	19X9	19X8
Net Margins	$ 255,250	$ 83,323
Adjustments to Reconcile Net Margins to Net Cash Provided by Operating Activities:		
Depreciation and Amortization	288,389	279,776
G&T and Other Capital Credits (Non-Cash)	(14,460)	(17,500)
Patronage Capital Credits-NRUCFC (Non-Cash)	(1,528)	(1,200)
Provision for Uncollectible Accounts Receivable	274	(526)
(Increase)/Decrease In:		
Customer and Other Accounts Receivable	(1,546)	2,523
Current and Accrued Assets-Other	79	112
Increase/(Decrease) In:		
Accounts Payable	12,102	5,117
Accrued Taxes	1,812	2,306
Deferred Energy Prepayments	3,629	2,246
Current and Accrued Liabilities-Other	5,824	(1,023)
Deferred Interest Expense	(418)	(525)
Total Adjustments	294,157	271,306
Net Cash Provided by Operating Activities	$ 549,407	$ 354,629

The accompanying notes are an integral part of these statements.

CENTER COUNTY ELECTRIC COOPERATIVE
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 19X9 AND DECEMBER 31, 19X8

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Include a brief description of the reporting entity's significant accounting policies in accordance with Accounting Principles Board Opinion No. 22, Disclosure of Accounting Policies.

Disclosure of accounting policies should identify and describe the accounting principles followed by the borrower and the methods of applying those principles that materially affect the determination of financial position, cash flow, and results of operations.

Disclosures of accounting policies do not have to be duplicated in this section if presented elsewhere as an integral part of the financial statements.

2. ASSETS PLEDGED:

Substantially all assets are pledged as security for long-term debt to REA.

3. ELECTRIC PLANT AND DEPRECIATION RATES AND PROCEDURES:

Listed below are the major classes of the electric plant as of December 31, 19X9, and 19X8:

	19X9	19X8
Intangible Plant	$ 2,194	$ 2,194
Distribution Plant	9,011,036	8,873,957
General Plant	511,416	489,113
Electric Plant in Service	9,524,646	9,365,264
Construction Work in Progress	407,943	317,166
	$9,932,589	$9,682,430

Provision has been made for depreciation of distribution plant at a straight-line composite rate of 2.86 percent per annum.

General Plant depreciation rates have been applied on a straight-line basis as follows:

Structures and Improvement	2.5%
Office Furniture	6.0%
Transportation Equipment	14.0%
Power Operated Equipment	12.0%
Other General Plant	4.0%
Communications Equipment	6.0%

4. INVESTMENTS IN ASSOCIATED ORGANIZATIONS:

Investments in associated organizations consisted of the following at December 31, 19X9 and 19X8:

	19X9	19X8
Capital Term Certificates of the National Rural Utilities Cooperative Finance Corporation (NRUCFC)	$ 385,193	$ 288,261
NRUCFC Patronage Capital Credits	5,065	3,537
Other	1,000	1,000
	$ 391,258	$ 292,798

5. DEFERRED CHARGES:

Following is a summary of amounts recorded as deferred charges as of December 31, 19X9 and 19X8:

	19X9	19X8
Preliminary Surveys 19X0 - X1 Work Plan	$ 5,666	$ 1,762

6. PATRONAGE CAPITAL:

At December 31, 19X9 and 19X8, patronage capital consisted of:

	19X9	19X8
Assignable	$ 255,250	$ 83,323
Assigned to Date	1,952,448	1,869,125
	2,207,698	1,952,448
Less: Retirements to Date	445,900	425,615
	$1,761,798	$1,526,833

Under the provisions of the Mortgage Agreement, until the equities and margins equal or exceed forty percent of the total assets of the cooperative, the return to patrons of contributed capital is generally limited to twenty-five percent of the patronage capital or margins received by the cooperative in the prior calendar year. The equities and margins of the cooperative represent 25.3 percent of the total assets at balance sheet date. Capital credit retirements in the amount of $20,285 were paid in 19X9.

7. OTHER EQUITIES:

At December 31, 19X9 and 19X8, other equities consisted of:

	19X9	19X8
Retired Capital Credits - Gain	$ 36,190	$ 34,990
Donated Capital	17,457	910
	$ 53,647	$ 35,900

8. MORTGAGE NOTES - REA:

Long-term debt is represented by mortgage notes payable to the United States of America. Following is a summary of outstanding long-term debt as of December 31, 19X9 and 19X8:

	19X9	19X8
2% Notes due March 31, 19X5	$1,057,155	$1,098,700
2% Notes due December 31, 19X6	2,485,927	2,502,370
5% Notes due December 31, 19X6	1,851,033	1,935,315
Less: Current Maturities	(145,000)	(140,000)
	$5,249,115	$5,396,385

Unadvanced loan funds of $285,600 are available to the cooperative on loan commitments from REA.

Principal and interest installments on the above notes are due quarterly in equal amounts of $99,600. As of December 31, 19X9, annual maturities of long-term debt outstanding for the next five years are as follows:

19X0	$145,000
19X1	$150,000
19X2	$151,500
19X3	$154,000
19X4	$155,000

Advance payments of $252,300 may be applied to the installments.

9. PENSION PLAN:

Substantially all of the employees of the Cooperative are covered by the ABC Retirement and Security Program, a multiemployer plan. Pension expense for the years ended 19X9 and 19X8 was $22,400.00 and $20,400.00, respectively.

10. DEFERRED CREDITS:

Following is a summary of the amounts recorded as deferred credits as of December 31, 19X9 and 19X8:

	19X9	19X8
Customer Energy Payments	$ 6,694	$ 3,065
Inventory Adjustment	5,210	7,500
	$ 11,904	$ 10,565

11. LITIGATION:

The cooperative is a defendant in an action in which the plaintiff claims damages totaling $200,000 for personal injuries sustained. The action has been dismissed by the District Court, but is on appeal before the State Supreme Court. Management is of the opinion that no liability will be incurred by the cooperative as a result of this action.

12. COMMITMENTS:

Under its wholesale power agreement, the cooperative is committed to purchase its electric power and energy requirements from Central Power Cooperative, Inc., until December 31, 19XX. The rates paid for such purchases are subject to review annually.

BILLING CODE 3410-15-C

Appendix B to Part 1773—Sample Auditor's Report for a Class A or B Commercial Telephone Company

Appendix B includes an example of a short-form auditor's report, report on compliance, report on internal controls, financial statements and accompanying notes for a commercial telephone company. The sample auditor's report is intended as a guide only and, while it is recommended that the format be followed, each auditor's report should be prepared to adequately cover the circumstances. To the extent possible, it should be used as a guide in preparing auditors' reports for other types of telephone borrowers.

Exhibit 1—Sample Auditor's Report

Certified Public Accountants, 1600 Main Street, City, State 24105, The Board of Directors, Center Telephone Company

Independent Auditor's Report

We have audited the accompanying balance sheets of Center Telephone Company as of December 31, 19X9 and 19X8, and the related statements of revenue and patronage capital, and cash flows for the years then ended. These financial statements are the responsibility of the cooperative's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with generally accepted auditing standards and the Government Auditing Standards, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Center Telephone Company as of December 31, 19X9 and 19X8, and the results of its operations and its cash flows for the years then ended in conformity with generally accepted accounting principles.

Certified Public Accountants, March 2, 19X0

Exhibit 2—Sample Report on Compliance When, Based on Assessments of Materiality and Audit Risk, the CPA Concluded It Was Not Necessary to Perform Tests of Compliance With Laws and Regulations

Certified Public Accountants, 1600 Main Street, City, State 24105, The Board of Directors Center Telephone Company

We have audited the financial statements of Center Telephone Company as of and for the years ended December 31, 19X9 and 19X8, and have issued our report thereon dated March 2, 19X0.

We conducted our audit in accordance with generally accepted auditing standards and the Government Auditing Standards, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

Compliance with laws, regulations, contracts, and grants applicable to Center Telephone Company is the responsibility of Center Telephone Company's management. As part of our audit, we assessed the risk that noncompliance with certain provisions of laws, regulations, contracts, and grants could cause the financial statements to be materially misstated. We concluded that the risk of such material misstatement was sufficiently low that it was not necessary to perform tests of Center Telephone Company's compliance with such provisions of laws, regulations, contracts, and grants. However, in connection with our audit, nothing came to our attention that caused us to believe that Center Telephone Company had not complied, in all material respects, with the laws, regulations, contracts, and grants referred to in the preceding paragraph.

This report is intended for the information of the audit committee, management, and the Rural Electrification Administration and supplemental lenders. This restriction is not intended to limit the distribution of this report, which is a matter of public record.

Certified Public Accountants, March 2, 19X0.

Exhibit 3—Sample Report on Compliance When, Based on Assessments of Materiality and Audit Risk, the CPA Performed Compliance Testing and Found No Material Instances of Noncompliance

Certified Public Accountants, 1600 Main Street, City, State 24105, The Board of Directors, Center Telephone Company

We have audited the financial statements of Center Telephone Company as of and for the years ended December 31, 19X9 and 19X8, and have issued our report thereon dated March 2, 19X0.

We conducted our audit in accordance with generally accepted auditing standards and the Government Auditing Standards, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

Compliance with laws, regulations, contracts, and grants applicable to Center Telephone Company is the responsibility of Center Telephone Company's management. As part of obtaining reasonable assurance about whether the financial statements are free of material misstatement, we performed tests of Center Telephone Company's compliance with laws, regulations, contracts, and grants. However, our objective was not to provide an opinion on overall compliance with such provisions.

The results of our tests indicate that, with respect to the items tested, Center Telephone Company complied, in all material respects, with the provisions referred to in the preceding paragraph. With respect to items not tested, nothing came to our attention that caused us to believe that Center Telephone Company had not complied, in all material respects, with those provisions.

This report is intended for the information of the audit committee, management, and the Rural Electrification Administration and supplemental lenders. This restriction is not intended to limit the distribution of this report, which is a matter of public record.

Certified Public Accountants, March 2, 19X0

Exhibit 4—Sample Report on Compliance When, Based on Assessments of Materiality and Audit Risk, the CPA Performed Compliance Testing and Found Material Instances of Noncompliance

Certified Public Accountants, 1600 Main Street, City, State 24105, The Board of Directors, Center Telephone Company

We have audited the financial statements of Center Telephone Company as of and for the years ended December 31, 19X9 and 19X8, and have issued our report thereon dated March 2, 19X0.

We conducted our audit in accordance with generally accepted auditing standards and the Government Auditing Standards, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

Compliance with laws, regulations, contracts, and grants applicable to Center Telephone Company is the responsibility of Center Telephone Company's management. As part of obtaining reasonable assurance about whether the financial statements are free of material misstatement, we performed tests of Center Telephone Company's compliance with laws, regulations, contracts and grants. However, our objective was not to provide an opinion on overall compliance with such provisions.

Material instances of noncompliance are failures to follow requirements or violations of prohibitions, contained in statutes, regulations, contracts, or grants that cause us to conclude that the aggregation of the misstatements resulting from those failures or violations is material to the financial statements. The results of our tests of compliance disclosed the following material instances of noncompliance, the effects of which have been corrected in Center Telephone Company's 19X9 and 19X8 financial statements.

(Include paragraphs describing the material instances of noncompliance noted.)

We considered these material instances of noncompliance in forming our opinion on whether Center Telephone Company's 19X9 and 19X8 financial statements are presented fairly, in all material respects, in conformity with generally accepted accounting principles, and this report does not affect our report dated March 2, 19X0 on those financial statements.

Except as described above, the results of our tests of compliance indicate that, with respect to the items tested Center Telephone Company complied, in all material respects, with the provisions referred to in the third paragraph of this report, and with respect to

items not tested, nothing came to our attention that caused us to believe that Center Telephone Company had not complied, in all material respects, with those provisions.

This report is intended for the information of the audit committee, management, and the Rural Electrification Administration and supplemental lenders. This restriction is not intended to limit the distribution of this report, which is a matter of public record.

Certified Public Accountants, March 2, 19X0

Exhibit 5—Sample Report on Internal Controls When Reportable Conditions Were Found

Certified Public Accountants, 1600 Main Street, City, State 24105, The Board of Directors, Center Telephone Company

We have audited the financial statements of Center Telephone Company as of and for the years ended December 31, 19X9 and 19X8, and have issued our report thereon dated March 2, 19X0.

We conducted our audit in accordance with generally accepted auditing standards and Government Auditing Standards, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

In planning and performing our audit of the financial statements of Center Telephone Company for the years ended December 31, 19X9 and 19X8, we considered its internal control structure in order to determine our auditing procedures for the purpose of expressing our opinion on the financial statements and not to provide assurance on the internal control structure.

The management of Center Telephone Company is responsible for establishing and maintaining an internal control structure. In fulfilling this responsibility, estimates and judgments by management are required to assess the expected benefits and related costs of internal control structure policies and procedures. The objectives of an internal control structure are to provide management with reasonable, but not absolute, assurance that assets are safeguarded against loss from unauthorized use or disposition, and that transactions are executed in accordance with management's authorization and recorded properly to permit the preparation of financial statements in accordance with generally accepted accounting principles. Because of inherent limitations in any internal control structure, errors or irregularities may nevertheless occur and not be detected. Also, projection of any evaluation of the structure to future periods is subject to the risk that procedures may become inadequate because of changes in conditions or that the effectiveness of the design and operation of policies and procedures may deteriorate.

For the purpose of this report, we have classified the significant internal control structure policies and procedures in the following categories (identify internal control structure categories).

For all of the internal control structure categories listed above, we obtained an understanding of the design of relevant policies and procedures and whether they have been placed in operation, and we assessed control risk.

We noted certain matters involving the internal control structure and its operation that we consider to be reportable conditions under standards established by the American Institute of Certified Public Accountants. Reportable conditions involve matters coming to our attention relating to significant deficiencies in the design or operation of the internal control structure that, in our judgment, could adversely affect the entity's ability to record, process, summarize, and report financial data consistent with the assertions of management in the financial statements.

(Include paragraphs to describe the reportable conditions noted).

A material weakness is a reportable condition in which the design or operation of the specific internal control structure elements does not reduce to a relatively low level the risk that errors or irregularities in amounts that would be material in relation to the financial statements being audited may occur and may not be detected within a timely period by employees in the normal course of performing their assigned functions.

Our consideration of the internal control structure would not necessarily disclose all matters in the internal control structure that might be reportable conditions and, accordingly, would not necessarily disclose all reportable conditions that are also considered to be material weaknesses as defined above. However, we believe none of the reportable conditions described above is believed to be a material weakness.

We also noted other matters involving the internal control structure and its operation that we have reported to the management of Center Telephone Company in a separate letter dated March 2, 19X0.

This report is intended for the information of the audit committee, management, and the Rural Electrification Administration and supplemental lenders. This restriction is not intended to limit the distribution of this report, which is a matter of public record.

Certified Public Accountants, March 2, 19X0

Exhibit 6—Sample Report on Internal Controls When No Reportable Conditions Were Found

Certified Public Accountants, 1600 Main Street, City, State 24105, The Board of Directors, Center Telephone Company

We have audited the financial statements of Center Telephone Company as of and for the years ended December 31, 19X9 and 19X8, and have issued our report thereon dated March 2, 19X0.

We conducted our audit in accordance with generally accepted auditing standards and Government Auditing Standards, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

In planning and performing our audit of the financial statements of Center Telephone Company for the years ended December 31, 19X9 and 19X8, we considered its internal control structure in order to determine our auditing procedures for the purpose of expressing our opinion on the financial statements and not to provide assurance on the internal control structure.

The management of Center Telephone Company is responsible for establishing and maintaining an internal control structure. In fulfilling this responsibility, estimates and judgments by management are required to assess the expected benefits and related costs of internal control structure policies and procedures. The objectives of an internal control structure are to provide management with reasonable, but not absolute, assurance that assets are safeguarded against loss from unauthorized use or disposition, and that transactions are executed in accordance with management's authorization and recorded properly to permit the preparation of financial statements in accordance with generally accepted accounting principles. Because of inherent limitations in any internal control structure, errors or irregularities may nevertheless occur and not be detected. Also, projection of any evaluation of the structure to future periods is subject to the risk that procedures may become inadequate because of changes in conditions or that the effectiveness of the design and operation of policies and procedures may deteriorate.

For the purpose of this report, we have classified the significant internal control structure policies and procedures in the following categories (identify internal control structure categories).

For all of the internal control structure categories listed above, we obtained an understanding of the design of relevant policies and procedures and whether they have been placed in operation, and we assessed control risk.

Our consideration of the internal control structure would not necessarily disclose all matters in the internal control structure that might be material weaknesses under standards established by the American Institute of Certified Public Accountants. A material weakness is a reportable condition in which the design or operation of one or more of the specific internal control structure elements does not reduce to a relatively low level the risk that errors or irregularities in amounts that would be material in relation to the financial statements being audited may occur and not be detected within a timely period by employees in the normal course of performing their assigned functions. We noted no matters involving the internal control structure and its operation that we consider to be material weaknesses as defined above.

However, we noted certain matters involving the internal control structure and its operation that we have reported to the management of Center Telephone Company in a separate letter dated March 2, 19X0.

This report is intended for the information of the audit committee, management, and the Rural Electrification Administration and supplemental lenders. This restriction is not intended to limit the distribution of this report, which is a matter of public record.

Certified Public Accountants, March 2, 19X0

BILLING CODE 3410-15-M

EXHIBIT 7 - SAMPLE FINANCIAL STATEMENTS

CENTER TELEPHONE COMPANY
BALANCE SHEETS - DECEMBER 31, 19X9 AND 19X8
ASSETS (Notes 1 and 2)

	19X9	19X8
CURRENT ASSETS:		
Cash - Construction Funds	$ 21,000	$ 18,000
Cash - General Funds	128,300	140,083
Telecommunications Accounts Receivable (less accumulated provision of $11,597 in 19X9 and $1,490 in 19X8)	139,642	122,623
Notes Receivable	2,500	3,000
Materials and Supplies	103,713	73,964
Prepayments (Note 3)	49,185	62,201
Other Current Assets	1,357	10,131
	445,697	430,002
NONCURRENT ASSETS:		
Nonregulated Investments: (Note 4)		
Net CATV Plant	413,511	407,086
Net Nonregulated Customer Premises Equipment	103,618	- 0 -
Deferred Maintenance and Retirements (Note 5)	40,000	45,000
	557,129	452,086
PROPERTY, PLANT, AND EQUIPMENT: (Note 6)		
Telecommunications Plant in Service	7,401,300	6,650,553
Telecommunications Plant Under Construction	67,626	199,092
Telecommunications Plant Adjustment (Note 7)	176,380	176,380
	7,645,306	7,026,025
Less: Accumulated Provision for Depreciation	1,760,587	1,504,255
	5,884,719	5,521,770
	$6,887,545	$6,403,858

The accompanying notes are an integral part of these statements.

CENTER TELEPHONE COMPANY
BALANCE SHEETS - DECEMBER 31, 19X9 AND 19X8
LIABILITIES AND EQUITIES

	19X9	19X8
CURRENT LIABILITIES:		
Accounts Payable	$ 123,689	$ 290,484
Notes Payable	61,600	70,400
Advance Billings and Payments	2,137	2,243
Customers Deposits	11,878	4,940
Current Maturities of Long-Term Debt (Note 8)	146,646	145,998
Accrued Taxes	242,076	224,566
Other Current Liabilities	8,500	9,079
	596,526	747,710
LONG-TERM DEBT:		
REA Mortgage Notes (Note 8)	4,592,658	4,128,106
OTHER LIABILITIES AND DEFERRED CREDITS:		
Unamortized Investment Tax Credits (Note 10)	53,078	61,377
Deferred Income Taxes (Note 11)	37,137	35,039
	90,215	96,416
STOCKHOLDERS' EQUITY:		
Capital Stock - Common $2 par value - 300,000 Shares Authorized; 102,600 Shares Outstanding 19X9 and 19X8	205,200	205,200
Additional Paid-in Capital	820,800	820,800
Retained Earnings (Note 8)	582,146	405,626
	1,608,146	1,431,626
	$6,887,545	$6,403,858

The accompanying notes are an integral part of these statements.

CENTER TELEPHONE COMPANY
STATEMENTS OF INCOME AND RETAINED EARNINGS
FOR THE YEARS ENDED DECEMBER 31, 19X9 and 19X8

	19X9	19X8
OPERATING REVENUES:		
Basic Local Network Services	$ 836,822	$ 862,205
Network Access Services	125,042	- 0 -
Long Distance Network Services	897,300	775,073
Miscellaneous	144,435	147,100
Less: Uncollectible Revenues	(24,000)	(24,500)
	1,979,599	1,759,878
OPERATING EXPENSES:		
Plant Specific Operations	564,486	480,509
Plant Nonspecific Operations	187,162	393,143
Depreciation and Amortization	274,691	
Customer Operations	94,473	78,772
Corporate Operations	157,453	134,127
	1,278,265	1,086,551
OPERATING TAXES:		
Federal and State Income Taxes - Operating (Notes 10 and 11)	159,845	170,687
Other Operating Taxes	225,013	204,230
Provision for Deferred Taxes (Note 10)	31,566	29,468
Investment Credits - Net	6,201	1,640
	422,625	406,025
OPERATING INCOME:	278,709	267,302
FIXED CHARGES:		
Interest on Long-Term Debt	88,432	85,854
Interest Charged to Construction - Credit	(2,251)	(1,516)
	86,181	84,338
NONREGULATED INCOME - NET (Note 4)	19,902	10,593
NET INCOME FOR PERIOD	212,430	193,557
Retained Earnings - January 1, 19X9 and 19X8	405,626	235,153
Dividends Declared	(35,910)	(23,084)
Retained Earnings - December 31, 19X9 and 19X8	$ 582,146	$ 405,626
Earnings Per Share of Common Stock - Average	$ 2.07	$ 1.89

The accompanying notes are an integral part of these statements.

CENTER COUNTY TELEPHONE COMPANY
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 19X9 AND 19X8

	19X9	19X8
CASH FLOWS FROM OPERATING ACTIVITIES:		
Cash Received from Consumers	$1,962,580	$1,733,289
Cash Paid to Suppliers and Employees	(1,159,158)	(960,459)
Interest Paid	(86,181)	(84,338)
Taxes Paid	(401,316)	(376,643)
Net Cash Provided by Operating Activities	315,925	311,849
CASH FLOWS FROM INVESTING ACTIVITIES:		
Construction and Acquisition of Plant	(619,281)	(507,617)
Investment in CATV Plant	(6,425)	(18,246)
Investment in Nonregulated CPE	(103,618)	
Plant Removal Costs	(18,359)	(27,216)
(Increase)/Decrease In:		
Materials Inventory	(29,749)	(19,478)
Notes Receivable	500	1,000
Deferred Maintenance and Retirements	5,000	(45,000)
Nonregulated Income	19,902	10,593
Net Cash Used in Investing Activities	(752,030)	(605,964)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Dividends Paid	(35,910)	(23,084)
Debt Proceeds	465,200	386,000
Payments on Short-term Debt	(8,800)	(7,500)
Increase/(Decrease) In:		
Consumer Deposits and Advance Payments	6,832	4,200
Net Cash Provided by Financing Activities	427,322	359,616
Net Increase/(Decrease) in Cash	(8,783)	65,501
Cash - Beginning of Year	158,083	92,582
Cash - End of Year	$ 149,300	$ 158,083

The accompanying notes are an integral part of these statements.

CENTER COUNTY TELEPHONE COMPANY
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 19X9 AND 19X8

RECONCILIATION OF NET MARGINS TO NET CASH PROVIDED BY OPERATING ACTIVITIES:

	19X9	19X8
Net Margins	$ 212,430	$ 193,557
Less: Nonregulated Income	(19,902)	(10,593)
Net Income from Regulated Operations	192,528	182,964
Adjustments to Reconcile Net Margins to Net Cash Provided by Operating Activities:		
Depreciation and Amortization	274,691	253,509
Provision for Uncollectible Accounts Receivable	10,107	(3,610)
(Increase)/Decrease In:		
Customer and Other Accounts Receivable	(27,126)	(22,979)
Current and Accrued Assets-Other	8,774	5,119
Prepaid Taxes	10,000	(10,000)
Other Prepaid Expenses	3,016	(5,426)
Increase/(Decrease) In:		
Accounts Payable	(166,795)	(126,472)
Accrued Taxes	17,510	37,742
Other Current Liabilities	(579)	(638)
Deferred Credits	(6,201)	1,640
Total Adjustments	123,397	128,885
Net Cash Provided by Operating Activities	$ 315,925	$ 311,849

The accompanying notes are an integral part of these statements.

CENTER TELEPHONE COMPANY
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 19X9 AND DECEMBER 31, 19X8

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Include a brief description of the reporting entity's significant accounting policies in accordance with Accounting Principles Board Opinion No. 22, Disclosure of Accounting Policies.

Disclosure of accounting policies should identify and describe the accounting principles followed by the borrower and the methods of applying those principles that materially affect the determination of financial position, cash flows, and results of operations.

Disclosures of accounting policies do not have to be duplicated in this section if presented elsewhere as an integral part of the financial statements.

2. ASSETS PLEDGED:

Substantially all assets are pledged as security for the long-term debt to REA.

3. PREPAID EXPENSES:

Following is a summary of the amounts recorded as prepaid items as of December 31, 19X9 and 19X8:

	19X9	19X8
Prepaid Taxes	$10,000	$20,000
Prepaid Insurance	3,000	3,000
Prepaid Rent	36,185	39,201
	$49,185	$62,201

4. NONREGULATED INVESTMENTS:

	19X9	19X8
CATV Plant in Service	$430,440	$420,940
CATV Plant Under Construction	9,051	6,500
Total CATV Plant	439,491	427,440
Less: Accumulated Depreciation	25,980	20,354
Net CATV Plant	$413,511	$407,086

CATV plant in service and under construction is stated at cost. The company provides for depreciation on a straight-line basis at annual

rates which will amortize the depreciable property over its estimated useful life.

The offering of CATV services does not involve the joint or shared use of assets in the provision of regulated and nonregulated services.

	19X9	19X8
Nonregulated Customer Premises Equipment - Leased	$109,699	- 0 -
Less: Accumulated Provisions for Depreciation	6,081	- 0 -
	$103,618	$ - 0 -

Nonregulated CPE is stated at cost. The company provides for depreciation on a straight-line basis at an annual rate of depreciation which will amortize the cost of the equipment over its estimated useful life. The leasing of nonregulated customer premises equipment does not involve the joint or shared use of assets in the provision of regulated and nonregulated services.

Following is a summary of net income from nonregulated investments for the year ending December 31, 19X9:

	CATV	Deregulated CPE	Total
Income from Operations	$32,425	$9,151	$41,576
Expenses	18,834	2,840	21,674
	$13,591	$6,311	$19,902

Income tax expense totaled $3,556, of which $2,883 was applicable to CATV operations and $673 was applicable to CPE leasing activities.

5 DEFERRED CHARGES:

The balance consists of the unamortized portion of the unprovided for loss in service value of plant retired.

Description	Date	Original Balance Net of Income-Tax Savings	Unamortized Balance 19X9	19X8
Aerial Plant	1/1/X7	50,000	40,000	45,000

The Public Utilities Commission granted the company permission to amortize this loss over a ten-year period net of income tax savings of $10,542.

6. INVESTMENT IN TELEPHONE PLANT:

Telephone plant in service and under construction is stated at cost. Listed below are the major classes of the telecommunications plant as of December 31, 19X9 and 19X8:

	19X9	19X8
Land	$ 64,601	64,601
Motor Vehicles	76,417	76,043
Special Purpose Vehicles	58,908	64,679
Other Work Equipment	43,582	40,022
Buildings	564,509	500,267
Furniture and Office Equipment	87,045	79,039
Central Office Equipment	3,171,162	2,746,871
Customer Premises Wiring	64,231	73,915
Poles, Cables, and Wire	2,458,895	2,300,411
Telecommunications Plant in Service - Unclassified	811,950	704,705
	$7,401,300	$6,650,553

The company provides for depreciation on a straight-line basis at annual rates which will amortize the depreciable property over its estimated useful life. Such provision as a percentage of the average balance of telephone plant in service was 7.2 percent in 19X9 and 7.1 percent in 19X8.

Individual plant depreciable rates are as follows:

Motor Vehicles	25%
Special Purpose Vehicles	13%
Other Work Equipment	16%
Buildings	4%
Furniture and Office Equipment	10%
Central Office Equipment	4%
Customer Premises Wiring	10%
Outside Plant - Aerial and Buried Cable	5%
Outside Plant - Pole Lines and Aerial Wire	20%

7. TELEPHONE PLANT ADJUSTMENT:

This adjustment represents the difference between the amount paid for the telephone plant plus associated expenses and the original cost of the plant less the associated depreciation. The company is amortizing the adjustment over a 19 1/2 year period in accordance with an order from the Public Utility Commission.

Annual amortization equals $9,000.

8. MORTGAGE NOTES:

Long-term debt is represented by mortgage notes payable to the United States of America. Following is a summary of outstanding long-term debt:

	19X9	19X8
5% Notes due December 31, 19X6	$4,739,304	$4,274,104
Less: Current Maturities	146,646	145,998
	$4,592,658	$4,128,106

As of December 31, 19X9, there were no unadvanced funds.

Principal and interest installments on the above notes are due quarterly in equal amounts of $63,200. The maturities of long-term debt for each of the five years succeeding the balance sheet date is as follows:

19X0	$146,649
19X1	$153,839
19X2	$155,743
19X3	$143,000
19X4	$139,976

The long-term debt agreements contain restrictions on the payment of dividends or redemption of capital stock. The terms of the Mortgage Agreement require the maintenance of defined amounts of member's equity and working capital after payment of dividends. Under these provisions approximately $293,688 of retained earnings was available for payment of dividends at December 31, 19X9.

9. PENSION PLAN:

Substantially all employees of the company are covered by the XYZ Retirement and Security plan, a multiemployer plan. Pension expense for the years ended 19X9 and 19X8 was $12,000.00 and $11,500.00, respectively.

10. INCOME TAXES AND DEFERRED INCOME TAXES:

The company uses a different method of depreciation on plant additions for income tax purposes. As provided by the Economic Recovery Tax Act of 1981, the company has elected to use the Accelerated Cost Recovery System (ACRS) method of depreciation for plant additions after 1980. In addition to the different depreciation practices for book and tax purposes, the company does not capitalize extraordinary maintenance and retirements and cost of removal charges for tax purposes. Provision is made in the statements of income and retained earnings for the taxes deferred as a result of

the above timing differences. The differences between accounting for book and tax purposes pertaining to income taxes and investment tax credits are accounted for using the normalization method of accounting, as is required for property placed in service after December 31, 1980, under the Economic Recovery Tax Act of 1981.

11. INVESTMENT TAX CREDITS:

The company follows the practice of recording investment tax credits as deferred income, to be amortized over the life of the assets providing the credit as required by the Public Service Commission. Accordingly, Federal income tax expense at December 31, 19X9, was reduced $7,400 by the investment tax credit amortization.

12. COMMITMENTS:

The company has executed contracts for construction programs for approximately $225,000 at December 31, 19X9. The amount unpaid against these commitments at December 31, 19X9 is $185,000.

BILLING CODE 3410-15-C

Appendix C to Part 1773—Sample Management Letter—Electric and Telephone

REA requires that CPAs auditing REA borrowers provide a management letter in accordance with § 1773.34. REA requires that this letter bear the same date as the auditor's report and be addressed to the borrower's board of directors. The CPA is required to sign the auditor's report, report on compliance, report on internal controls, and management letter.

Certified Public Accountants, 1600 Main Street, City, State 24105, March 2, 19X0, Board of Directors

We have audited the financial statements of (company) for the years ended December 31, 19X9 and 19X8, and have issued our report thereon dated March 2, 19X0.

Comments

A statement that the audit has been performed in accordance with 7 CFR Part 1773.

A statement as to whether any special report, summary of recommendations or similar communications was furnished to the borrower's management during the course of the audit or during interim audit work.

Required Comments on Specified Financial and Accounting Matters (as detailed in § 1773.34).

Accounting and Records
Materials Control
Compliance with REA Security Instrument Provisions
Reports to REA
Service Contracts
Income Tax Status
Related Party Transactions
Deferred Debits and Deferred Credits
Depreciation Rates
Insurance Certification
Other Comments and Recommendations

This letter supplements the information included in the financial statements and notes. It is intended solely for the use of management, the Rural Electrification Administration, and supplemental lenders and should not be used for any other purpose.

In accordance with the terms of our audit agreement, we are enclosing copies of the auditor's report, report on compliance, report on internal controls, and management letter for each member of the Board, the Manager, and other required distribution. Two copies of the auditor's report, report on compliance, report on internal controls, and management letter should be transmitted to the REA and one copy transmitted to each supplemental lender, where applicable.

Certified Public Accountants

Dated: October 11, 1991.

Gary C. Byrne,

Administrator.

[FR Doc. 91-28759 Filed 12-2-91; 8:45 am]

BILLING CODE 3410-15-M

DEPARTMENT OF AGRICULTURE

Rural Electrification Administration

Agency Information Collection Under Office of Management and Budget (OMB) Review for Policy on Audits of REA Borrowers

AGENCY: Rural Electrification Administration, USDA.

ACTION: Expedited information collection request.

SUMMARY: The Rural Electrification Administration (REA) has requested the Office of Management and Budget (OMB) to approve the information collection of the final rule, Policy on Audits of REA Borrowers (part 1773), on an expedited basis by December 27, 1991. This final rule is published elsewhere in this **Federal Register** issue. Due to REA's request for an expedited review, REA is publishing the supporting statement for this information collection, in its entirety, in this notice.

DATES: Comments must be submitted on or before December 18, 1991.

ADDRESSES: Comments must be mailed to the Office of Information and Regulatory Affairs, Office of Management and Budget, room 3201, Washington, DC 20503; or to USDA, Office of Information Resources Management, room 408W, Administration Building, Washington, DC 20250; Attention: Mr. Don Hulcher.

FOR FURTHER INFORMATION CONTACT: Mr. Don Hulcher, address as above, (202) 720–6746.

SUPPLEMENTARY INFORMATION: REA has requested that OMB approve the information collection for the final rule "Policy on Audits of REA Borrowers" on an expedited basis to facilitate an effective date of December 31, 1991. This final rule is published elsewhere in this issue.

The standard REA security instrument contains a provision requiring REA borrowers to prepare and furnish to REA, at least once during each 12–month period, a full and complete report of its financial condition, operations, and cash flows, in form and substance satisfactory to REA, audited and certified by an independent certified public accountant (CPA), satisfactory to REA, and accompanied by a report of such audit, in form and substance satisfactory to REA. The required report is prepared as of a fiscal year end established by the borrower. Part 1773 sets forth the requirements for performing and submitting annual audit reports to REA. Approximately 75% of the REA borrowers have established fiscal years ending as of December 31. Therefore, it is critical that the final rule "Policy on Audits of REA Borrowers" and the information collection become effective for audits "as of" December 31, 1991. Since this information is collected only once a year, REA will lose an entire year's information reporting under the revised regulation if part 1773 is not effective for audits "as of" December 31, 1991.

An effective date of December 31, 1991, will also eliminate any confusion or uncertainty for the borrowers and their CPAs as to which audit requirements prevail. While all audit work is performed as of the fiscal year end (for example, December 31), a substantial portion of the audit procedures are performed during first quarter of the following year. If part 1773 becomes effective in January or February, 1992, many CPAs may be uncertain as to what procedures to apply. The resulting information collected by REA may be inconsistent. Therefore, to ensure uniformity in auditing and reporting procedures and to ensure that the information collected by REA is not improperly skewed, it is essential that an effective date of December 31, 1991, be imposed.

The supporting statement for the information collection associated with part 1773 is as follows:

A. Justification

1. Explain the circumstances that make the collection of information necessary.

The requested financial statements are needed to (1) evaluate borrowers' financial performance, (2) determine whether current loans are at financial risk, and (3) determine the credit worthiness of future loans.

Under the authority of the Rural Electrification Act of 1936 (Act), as amended 7 U.S.C. 901 et seq., the Administrator is authorized and empowered to make loans under certain specified circumstances. As a requirement for these loans, the REA mortgage in Article 2, Section 12, requires the Mortgagor to prepare and furnish financial statements to REA at least once during each 12–month period.

Departmental Regulation 1700–1, Basic Office of Inspector General Investigation/Audit Organization and Procedures, further requires that all audits required by United States Department of Agriculture agencies and conducted by nonfederal auditors be performed in accordance with generally accepted government auditing standards (GAGAS).

2. Indicate how, by whom, and for what purpose the information is to be used and the consequence to Federal program or policy activities if the collection of information was not conducted.

REA, in representing the Federal Government as Mortgagee and in furthering the objectives of the Act, relies on the information provided by the borrowers in their financial statements to make lending decisions as to borrowers' credit worthiness and to assure that loan funds are approved, advanced, and disbursed for proper Act purposes. These financial statements are audited by a certified public accountant to provide independent assurance that the data being reported are properly measured and fairly presented. If this information is not obtained, REA would not be able to make informed lending decisions and would be unable to effectively administer its programs.

3. Describe any consideration of the use of improved information technology to reduce burden and any technical or legal obstacles to reducing burden.

The financial statements are prepared by the borrowers from general accounting records and audited by the certified public accountants utilizing audit programs established within the individual accounting firms. REA prescribes general audit procedures and documentation requirements but does not regulate the method in which the accounting records are maintained or the audit steps are performed. Borrowers may use either manual or automated accounting systems, as best fit their needs, and CPAs may use manual or automated auditing systems.

4. Describe efforts to identify duplication.

The general purpose financial statements for REA borrowers with fiscal dates other than December 31 are not duplicated on any other report. The reports required by GAGAS on compliance testing and internal controls are not duplicated in any other format. Interim financial reports that may duplicate data submitted in the annual report are not required to be prepared. If borrowers elect to prepare interim reports for managements' evaluations, they are not required to furnish these reports to REA.

5. Show specifically why any similar information already available cannot be used or modified for use for the purpose(s) described in 2.

General purpose financial information is provided at December 31 for all borrowers. This information, however, is not audited and does not contain the compliance testing required under GAGAS.

6. If the collection of information involves small businesses or other small

entities, describe the methods used to minimize burden.

The burden placed on small business is minimized because the information reported in the financial statements may be taken directly from the borrowers' accounting records. REA continually reviews the information collected to determine whether it is possible to reduce the burden for all REA borrowers.

7. Describe the consequence to Federal program or policy activities if the collection were conducted less frequently.

The annual reporting of financial information is considered the standard for all business enterprises. Collecting the information less frequently would delay REA's analysis of the borrower's financial strength, thereby adversely impacting current lending decisions. It would also delay corrective action on improper accounting issues and financial downturns.

8. Explain any special circumstances that require the collection to be conducted in a manner inconsistent with the guidelines in 5 CFR 1320.6.

No special circumstances exist that require the collection to be conducted in a manner inconsistent with the guidelines in 5 CFR 1320.6.

9. Describe efforts to consult with persons outside the agency to obtain their views on the availability of data, frequency of collection, the clarity of instructions and recordkeeping, disclosure or reporting format (if any), and on the data elements to be recorded, disclosed, or reported.

Each program participant signs a mortgage agreement that specifically requires the submission of annual, audited financial statements. Therefore, all REA borrowers are fully aware of the reporting requirements and additional consultations are not made. When revisions are made in the audit reporting requirements, Part 1773 is published in the **Federal Register** and public comment is invited.

10. Describe any assurance of confidentiality provided to respondents and the basis for the assurance in statute, regulation, or agency policy.

The financial statements do not contain information requiring confidentiality.

11. Provide additional justification for any questions of a sensitive nature, such as sexual behavior and attitudes, religious beliefs, and other matters that are commonly considered private.

The financial statements do not contain questions of a sensitive nature.

12. Provide estimates of annualized cost to the Federal Government and to the respondents. Also provide a description of the method used to estimate cost, which should include quantification of hours, operational expenses (such as equipment, overhead, printing, and support staff) and any other expense that would not have been incurred without the paperwork burden.

The following is a summary of the estimated costs:

Annual Cost to the Federal Government:

a. Review and processing of audit reports

Professional Time:	
1,800 responses×6.0 hrs.×$20=	$216,000
Clerical Time:	
1,800 responses×2.0 hrs.×$9=	32,400
Total	248,400

Annual Cost to Respondents: (Refer to chart in 13 below.)

b. Notification of selection of the CPA

Professional Time:	
100 responses×0.2 hrs.×$25=	$500
Clerical Time:	
100 responses×0.4 hrs.×$10=	400
Total	900

c. Submission of auditor's report

Professional Time:	
1,800 responses×0.0 hrs.×$25=	$0
Clerical Time:	
1,800 responses×0.2 hrs.×$10=	3,600
Total	3,600

d. Submission of plan of corrective action

Professional Time:	
1,800 responses×8.0 hrs.×$25=	$360,000
Clerical Time:	
1,800 responses×3.0 hrs.×$10=	54,000
Total	414,000
Total	418,500

Annual Cost to Certified Public Accountants:

e. Notification of participation in a peer review program

Professional Time:	
10 responses×.2 hrs.×$100=	$ 200
Clerical Time:	
10 responses×.4 hrs.×$ 15=	60
Total	260

f. Submission of peer review report

Professional Time:	
150 responses×.0 hrs.×$100=	$ 0
Clerical Time:	
150 responses×.2 hrs.×$ 15=	450
Total	450

g. Notification of Scope Limitation

Professional Time:	
2 responses×.2 hrs.×$100=	$ 40
Clerical Time:	
2 responses×.0 hrs.×$ 15=	0
Total	40

h. Notification of Irregularities

Professional Time:	
10 responses×1.0 hr.×$100=	$ 1,000
Clerical Time:	
10 responses×1.0 hr.×$ 15=	150
Total	1,150
Total	1,900

13. Provide estimates of the burden of the collection of information.

The following chart describes the reporting burden on borrowers and certified public accountants:

Loan application items	No. of respondents	No. of responses/ respondent	Total annual responses	Hours per response	Total hours
b. Selection of CPA	100	1	100	.6	60.0
c. Auditor's report	1,800	1	1,800	.2	360.0
d. Plan of corrective action	1,800	1	1,800	11.0	19,800.0

Loan application items	No. of respondents	No. of responses/ respondent	Total annual responses	Hours per response	Total hours
e. Notification peer review	10	1	10	.6	6.0
f. Submission peer review	150	1	150	.2	30.0
g. Scope limitation	2	1	2	.2	.4
h. Irregularities	10	1	10	2.0	20.0
Totals		3,872	20,276.4		

b. Notification of selection of the CPA. This collection is necessary only when the borrower changes CPA firms. It is estimated that each year, approximately 100 borrowers select a CPA firm different from the previous year. Preparation will require approximately 30–40 minutes.

c. Submission of auditor's report. All REA borrowers (approximately 1,800) are required to submit copies of the audited financial statements and auditors' reports. Mailing should take no more than 10 minutes.

d. Submission of plan of corrective action. It is estimated that all borrowers will have recommendations of some nature that will require a response. The average preparation time is estimated at 8 hours of professional time to develop the response and 3 hours of clerical time to type and submit the response.

e. Notification of participation in a peer review program. Only those CPA firms that have not previously audited REA borrowers must submit this information. It is estimated that only 10 new firms enter the REA program each year. Preparation will require approximately 30–40 minutes.

f. Submission of peer review report. Each CPA firm must have a peer review performed every three years. Approximately 450 firms audit within the REA program; therefore, approximately 150 firms must submit their reports each year. Submission requires mailing only which we estimate should take no more than 10 minutes.

g. Notification of Scope Limitation. Scope limitations are very rare; therefore, we estimate no more than 2 each year. Notification is made by telephone. We estimate that this communication should take no more than 10 minutes.

h. Notification of irregularities. We estimate that 10 irregularities occur each year. Notification must be in writing. Preparation of the notice will require an average of 1 hour of professional time and 1 hour of clerical time.

14. Explain reasons for changes in burden, including the need for any increase.

There is no previously calculated record of burden hours.

15. For collections of information whose results are planned to be published for statistical use, outline plans for tabulation, statistical analysis, and publication. Provide the time schedule for the entire project, including beginning and ending dates of the collection of information, completion of report, publication dates, and other actions.

The information collected will not be published for statistical use.

B. Collection of Information Employing Statistical Methods

There is no collection of information employing statistical methods.

Dated: November 25, 1991.

Gary C. Byrne,

Administrator.

[FR Doc. 91-28758 Filed 12-2-91; 8:45 am]

BILLING CODE 3410-15-M

Tuesday
December 3, 1991

Part IV

Department of the Interior

Bureau of Alcohol, Tobacco, and Firearms

27 CFR Part 5
Vodka Identity Standards; Compliance Date Deferral; Final Rule

DEPARTMENT OF THE TREASURY

Bureau of Alcohol, Tobacco, and Firearms

27 CFR Part 5

[T.D. ATF-317; Re: T.D. ATF-311, T.D. ATF-306, Notice Nos. 716, 403, 410, 583; 91F009P]

RIN: 1512-AA10

Vodka: Deferral of Compliance Date

AGENCY: Bureau of Alcohol, Tobacco, and Firearms (ATF), Department of the Treasury.

ACTION: Final rule, Treasury decision.

SUMMARY: This final rule defers the compliance date set forth in T.D. ATF-311 with respect to the citric acid limitation set forth in section 5.23(a)(3)(ii) by T.D. ATF-306. The deferral of the compliance date is necessary in order to allow ATF to evaluate the disparate sensory test results recently received concerning maximum levels for the use of citric acid in vodka.

DATES: This document is effective upon publication. The compliance date for § 5.23(a)(3)(ii) with respect to the citric acid limitation is September 3, 1992.

FOR FURTHER INFORMATION CONTACT: David W. Brokaw, Wine and Beer Branch, (202) 927-8230.

SUPPLEMENTARY INFORMATION:

Background

T.D. ATF-306, (55 FR 49994, dated December 4, 1990), amended 27 CFR 5.23(a)(3) to authorize the use of up to 2 grams per liter (2,000 parts per million) of sugar, and a trace amount (defined as 150 milligrams per liter or 150 parts per million) of citric acid in the production of vodka. T.D. ATF-306 was effective January 3, 1991, with a formula and label cancellation date of March 4, 1991, for products not made within the limitations of the Treasury decision.

Petition

On March 4, 1991, ATF issued T.D. ATF-311 (56 FR 8922) deferring the compliance date with respect to the citric acid limitation set forth in § 5.23(a)(3)(ii) by T.D. ATF-306. T.D. ATF-311 was issued in response to a petition from Heublen, Inc., for the reconsideration of T.D. ATF-306. Heublein's petition was based on a representation that new scientific information and data not previously available had come to their attention concerning maximum levels for the use of citric acid in vodka.

Notice No. 716

On April 29, 1991, ATF issued Notice No. 716 (56 FR 19623) to gather additional information by inviting comments from the public and industry as to whether the 150 ppm citric acid limitation set forth in T.D. ATF-306 should be retained or revised. During the comment period, ATF secured an outside testing firm to conduct independent testing on sensory threshold levels for citric acid addition to vodka.

In response to Notice No. 716, ATF received ten comments. All of the comments were opposed to setting a maximum limitation as low as 150 ppm for the addition of citric acid to vodka. The only commenter submitting sensory test data from independent contractors was Heublein, Inc. An evaluation of the test data by ATF revealed a disparity between the Heublein independent contractors' test results and the sensory test results from the outside firm. Therefore, the compliance date of December 4, 1991, set forth in T.D. ATF-311 is being deferred for nine months in order to allow time to resolve the disparity in test results.

Notice and Public Procedure

Because this final rule merely postpones the compliance date with respect to the citric acid requirement in T.D. ATF-306 in order to evaluate recently acquired test information submitted by the industry to ATF, and in view of the immediate need for guidance to the industry with respect to compliance with this provision in T.D. ATF-306, it is found to be impractical and contrary to the public interest to issue this rule with notice and public procedure thereon under 5 U.S.C. 553(b) or subject to the effective date limitation of 5 U.S.C. 553(d).

Regulatory Flexibility Act

The provisions of the Regulatory Flexibility Act relating to a final regulatory flexibility analysis (5 U.S.C. 604) are not applicable to this final rule because the agency was not required to publish a general notice of proposed rulemaking under 5 U.S.C. 553 or any other law.

Executive Order 12291

In compliance with Executive Order 12291, ATF has determined that this final rule is not a "major rule" since it does not result in:

(a) An annual effect on the economy of $100 million or more;

(b) Major increases in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions;

(c) Significant adverse effects on competition, employment, investment, productivity, innovation, or on the ability of United States-based enterprises to compete with foreign-based enterprises in domestic or export markets.

Paperwork Reduction Act

The provisions of the Paperwork Reduction Act of 1980, Public Law 96-511, 44 U.S.C. chapter 35, and its implementing regulations, 5 CFR part 1320, do not apply to this final rule because no requirement to collect information is imposed.

Disclosure

Copies of the petition, the notices, the Treasury decision, and all comments are available for public inspection during normal business hours at: ATF Reading Room, room 6300, 650 Massachusetts Avenue NW., Washington, DC.

Drafting Information

The principal author of this document is David W. Brokaw, Wine and Beer Branch, Bureau of Alcohol, Tobacco, and Firearms.

Therefore, pursuant to the authority set forth in 27 U.S.C. 205(e), ATF is further postponing the compliance date with respect to the citric acid limitation set forth in 27 CFR 5.23(a)(3)(ii) by T.D. ATF-306. The compliance date is September 3, 1992.

Signed: November 12, 1991.

Stephen E. Higgins,

Director.

Approved:

John P. Simpson,

Acting Assistant Secretary (Enforcement).

[FR Doc. 91-29003 Filed 12-2-91; 9:42 am]

BILLING CODE 4810-31-M

Reader Aids

Federal Register

Vol. 56, No. 232

Tuesday, December 3, 1991

INFORMATION AND ASSISTANCE

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Index, finding aids & general information	202-523-5227
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FEDERAL REGISTER PAGES AND DATES, DECEMBER

CFR PARTS AFFECTED DURING DECEMBER

At the end of each month, the Office of the Federal Register publishes separately a List of CFR Sections Affected (LSA), which lists parts and sections affected by documents published since the revision date of each title.

LIST OF PUBLIC LAWS

This is a continuing list of public bills from the current session of Congress which have become Federal laws. It may be used in conjunction with "P L U S" (Public Laws Update Service) on 202-523-6641. The text of laws is not published in the **Federal Register** but may be ordered in individual pamphlet form (referred to as "slip laws") from the Superintendent of Documents, U.S. Government Printing Office, Washington, DC 20402 (phone, 202-512-2470).

H.R. 2521/Pub. L. 102-172

Department of Defense Appropriations Act, 1992. (Nov. 26, 1991; 105 Stat. 1150; 67 pages) Price: $1.50

S. 1475/Pub. L. 102-173

Protection and Advocacy for Mentally Ill Individuals Amendments Act of 1991. (Nov. 27, 1991; 105 Stat. 1217; 3 pages) Price: $1.00

S.J. Res. 207/Pub. L. 102-174

To designate the period commencing on November 24, 1991, and ending on November 30, 1991, and the period commencing on November 22, 1992, and ending on November 28, 1992, each as "National Adoption Week". (Nov. 27, 1991; 105 Stat. 1220; 2 pages) Price: $1.00

Last List December 2, 1991